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U.S. NATURAL GAS AVAILABILITY

CONVENTIONAL GAS SUPPLY THROUGH THE YEAR 2000

A TECHNICAL MEMORANDUM

SEPTEMBER 1983

Technical Memoranda are issued by OTA on specific subjects analyzed in recent OTA reports or on projects presently in process at OTA. They are issued at the request of Members of Congress who are engaged in committee legislative actions which are expected to be resolved before OTA completes its assessment.

CONGRESS OF THE UNITED STATES
Office of Technology Assessment
Washington, D. C. 20510

Recommended Citation:

U.S. Natural Gas Availability: Conventional Gas Supply Through the Year 2000—A Technical Memorandum (Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-TM-E-12, September 1983).

Library of Congress Catalog Card Number 83-600584

For sale by the Superintendent of Documents,
U.S. Government Printing Office, Washington, D.C. 20402

Foreword

This technical memorandum is an interim product of OTA's assessment of "U.S. Natural Gas Availability." The assessment is examining the future potential for production of all forms of natural gas in the U.S. Lower 48 States, emphasizing the time frame 1990-2000. Gas production in this period will depend primarily on gas that will be made available from the growth of already-discovered fields, from new discoveries of conventional gas, and from the exploitation of those "unconventional" gas sources that today are close to commercial feasibility. The House Committee on Energy and Commerce and its Subcommittee on Fossil and Synthetic Fuels requested the assessment, and the request was endorsed by the Subcommittee on Energy Research and Development of the Senate Committee on Energy and Natural Resources.

This technical memorandum discusses the future availability of conventional gas—gas that can be produced at prices and with technology that are relatively close to today's. We first examine the efficacy of different generic resource assessment methods, review specific estimates (including those of the U.S. Geological Survey and the Potential Gas Committee), present alternative arguments concerning specific areas of uncertainty such as the amount of gas to be found in small fields, and describe OTA's conclusions about a plausible range for the size of the conventional gas resource. Next, we discuss trends in reserve additions and production, leading up to a projection of production potential to the year 2000. Finally, we review the potential from gas sources other than domestic production.

The material in this technical memorandum is being released at this time to assist Congress during the current debate over natural gas. The material will also be incorporated, along with OTA's analysis of unconventional gas sources, in a final assessment report to be published at the conclusion of the U.S. Natural Gas Availability study.

OTA is grateful for the assistance of its assessment advisory panel, its contractors, its colleagues at the Congressional Research Service and U.S. Geological Survey, and the many others who provided advice and information. However, OTA assumes full responsibility for this technical memorandum, which does not necessarily represent the views of individual members of the advisory panel.

John H. Gibbons

JOHN H. GIBBONS
Director

U.S. Natural Gas Availability Advisory Panel

William Vogely, *Chairman*
Department of Mineral Economics, Pennsylvania State University

Marc Cooper
Research Director
Consumer Energy Council of America

Lloyd Elkins
Petroleum Consultant
Tulsa, Okla.

Ed Erickson
Professor of Economics and Business
North Carolina State University

Daniel Grubb
Vice President of Gas Supply
Natural Gas Pipeline Company of America

John Haun
Professor of Geology
Colorado School of Mines

Donald Kash
George Lynn Cross Research Professor of Political Science, and Research Fellow
Science and Public Policy Program
University of Oklahoma

Harry C. Kent
Director
Potential Gas Agency

Lawrence Moss
Independent Consultant
Estes Park, Calif.

Roy E. Roadifer
Chief Geologist
Mobil Oil Corp.

Benjamin Schlesinger
Principal
Booz, Allen & Hamilton, Inc.

John C. Sharer
Assistant Director
Unconventional Natural Gas
Gas Research Institute

John Weyant
Deputy Director
Energy Modeling Forum
Stanford University

John Schanz
Senior Specialist in Energy Resource Policy
Congressional Research Service

ACKNOWLEDGMENTS

Many people contributed to this technical memorandum by providing information, advice, and substantive reviews of draft materials. We would like to acknowledge the valuable contributions of the following individuals:

- Lawrence Drew, David Root, John Houghton, Richard Meyer, U.S. Geological Survey, Reston, Va.
- Dudley Rice, Gordon Dolton, U.S. Geological Survey, Denver, Colo.
- Richard O'Neill, Energy Information Administration, U.S. Department of Energy
- Thomas Woods, Gas Research Institute
- Paul Ching, Shell Oil Company
- Wallace Howes, Natural Gas Pipeline Company of America
- Robert Kalisch, Michael German, Jeffrey Wingenroth, American Gas Association
- John Scheunemayer, University of Delaware
- J. N. Sommerfrucht, David White, Bill James, Robert Megill, Warren Strickland, W. R. Finger, Exxon Company, U.S.A.
- William Fisher, University of Texas at Austin
- Scott Farrow, Carnegie Mellon University
- Gary Pagliano, Congressional Research Service

OTA U.S. Natural Gas Availability Project Staff

Lionel S. Johns, *Assistant Director, OTA*
Energy, Materials, and International Security Division

Richard E. Rowberg, *Energy and Materials Program Manager*

Steven E. Plotkin, *Project Director*
Julia C. Crowley, *Unconventional Gas Sources*
Vykie G. Smoyer, *Natural Gas Basics, Other Sources*
David Strom, *Computer Supply Models*

Administrative Staff

Lillian Quigg Edna Saunders

Other Contributors

Joseph Riva, *Congressional Research Service*
Kathryn White, *Independent consultant: editor*

Contractors and Consultants

Richard Nehring, Pacific Palisades, Calif.
Jensen Associates, Inc., Fairfax, Va.

OTA Publishing Staff

John C. Holmes, *Publishing Officer*
John Bergling Kathie S. Boss Debra M. Datcher Joe Henson
Glenda Lawing Linda A. Leahy Cheryl Manning

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Chapter 1

Summary

Chapter 1

Summary

INTRODUCTION

Within the last 5 years or so, the general perception about the outlook for future U.S. gas supplies has moved from pessimism to considerable optimism. The pessimism was based partly on short-term problems, such as periodic regional shortages, and partly on disturbing long-term trends, such as the declining finding rate for new gasfields and, since the late 1960's, the ominous and apparently unstoppable decline of proved reserves. The new optimism is based on several factors, including the gas "bubble" caused by declining gas demand coupled with high gas deliverability, the rebound of reserve additions to levels which exceeded production in 1978 and 1981, and continuing optimistic estimates of domestic gas resources by the U.S. Geological Survey (USGS) and the industry-based Potential Gas Committee (PGC).

What does this apparent change in the outlook for U.S. natural gas supply mean? Can we now count on natural gas to play a major, perhaps even expanded role in satisfying U.S. energy requirements, or is the seeming turnabout only a temporary respite from a continuing decline in gas reserve levels and, soon to follow, a decline in gas production capabilities?

This technical memorandum presents the first phase of OTA's assessment of these questions: an evaluation of the future prospects for the discovery and production of conventional natural gas in the Lower 48 States. The memorandum examines the gas resource base and future production potential under the following conditions:

- *wellhead prices* are assumed not to change substantially from today's levels in real terms,
- *new technologies* that are not readily foreseeable extensions of existing technology are not considered, and
- *demand* is assumed to be high enough to avoid reductions in production potential due to curtailment of investments in exploration and production.

The memorandum also summarizes the prospects for additional conventional supplies to the Lower 48 from pipeline imports from Canada, Alaska, and Mexico, liquefied natural gas (LNG) imports, and synthetic gas from coal. The final report of OTA's assessment also will evaluate the so-called "unconventional" sources of natural gas—gas in tight sands, Devonian shales, coal seams, and geopressurized brines.

MAJOR FINDINGS

Certain technical uncertainties—primarily those associated with incomplete geological understanding, alternative interpretations of past discovery trends, and difficulties in projecting likely patterns of future gas discoveries—are so substantial that *by themselves* they prevent a reliable estimation of the remaining recoverable gas resource and the likely year 2000 production rate. Even after ignoring the potential for significant changes in gas prices and technology in the future, **OTA could not narrow its range of estimates of resources and future production beyond a factor of 2 from the lowest to the highest estimate.** Inclusion of uncertainties associated with changing gas prices and market demand and the continuing evolution of gas exploration and production technology would undoubtedly widen the range still further.

Specific findings of the study are as follows:

- Current proved reserves in the Lower 48 States will supply only a few trillion cubic feet (TCF) per year of production by the year 2000. All other domestic production must come from gas which has not yet been identified by drilling.
- There is no convincing basis for the common argument that the area of the Lower 48 States is so intensively explored and its geology is

so well known that there is a substantial consensus on the magnitude of the gas resource base. Plausible estimates of the amount of remaining conventional natural gas in the Lower 48 States that is recoverable under present and easily foreseeable technological and economic conditions range from 400 to 900 TCF. At the lower end of this range, production in the year 2000 will be seriously constrained by the magnitude of the resource base.

- Assuming market conditions favorable to gas exploration and production and no radical changes in technology or gas prices, plausible estimates of the year 2000 production potential of conventional natural gas in the Lower 48 States range from 9 to 19 TCF/yr. In 1990 production is likely to be anywhere from 13 to 20 TCF/yr.
- Because it is unclear whether the recent surge in the rate of additions to proved gas reserves* is sustainable, the range of plausible annual reserve additions is wide even for the near future. The range for the Lower 48 States for 1986 and beyond is from 7 or 8 TCF/yr up to 16 or 17 TCF/yr, assuming that the current excess of gas production capacity ceases and market conditions improve.
- The rate at which gas can be withdrawn from proved reserves, or R/P (reserves-to-production) ratio, may range from 7.0 to 9.5 as a national average by the year 2000, further adding to the difficulty of projecting future production potential.
- An important source of uncertainty in evaluating past discovery trends is the lack of publicly available, unambiguous, disaggregated data about gas discoveries.

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*The 1981 addition was about 21 TCF versus about 10 TCF/yr or less for 1969-77.

NATURAL GAS PRODUCTION POTENTIAL

OTA finds insufficient evidence on which to base either an optimistic or a pessimistic outlook for conventional domestic gas production. Given market conditions favorable to gas exploration and production, the production of natural gas from conventional sources within the Lower 48 States could range from 9 to 19 TCF/yr by the year 2000. Similarly, production in the year 1990 could range from 13 to 20 TCF/yr.* These ranges **do not include gas from pipeline or LNG imports, synthetic gas from coal or other materials, or gas from unconventional sources** that are not producing today. They do include gas from low-permeability reservoirs that is currently economically recoverable, even though this gas is borderline conventional and might be considered unconventional by some assessors.

OTA's wide range for plausible levels of conventional gas production in the Lower 48 States in the year 2000 is in sharp contrast to the relatively *narrow* range displayed in publicly available forecasts. Table 1 presents the summarized results of 20 separate forecasts from oil companies, other private institutions and individuals, and Government agencies. A striking feature of this group of forecasts is that 13 of the 14 forecasts that project a year 2000 production level fall within *11 to 15 TCF/yr*. This high level of agreement for a production rate two decades in the future is made all the more unusual by the probability that there are substantive differences in the baseline assumptions used by the various forecasters. The high level of agreement might, however, reflect the probability that the forecasts are not all independent, original estimates; some may simply be averages of other forecasts, reflecting the "conventional wisdom," and some may have been influenced by others that preceded them.

The wide range in OTA's projection of future gas production reflects the existing high degree of uncertainty about:

1. the magnitude and character of the gas resource base;
2. the appropriate interpretation and extrapolation of past trends in natural gas discovery, and;
3. the rapidity with which gas in proved reserves can be produced, expressed as the reserves-to-production (R/P) ratio.

---

*Current annual production is about 18 TCF/yr, and actual production *capacity* is probably 1 or 2 TCF/yr higher.

Table 1.—Gas Production Forecasts (in trillion cubic feet)

	Oil companies	Other private	Government agencies	Average	OTA
1985					
Lowest	17.0	15.5	16.5	—	—
Average	18.7	17.1	17.3	17.9	—
Highest	19.5	18.3	18.0	—	—
1990					
Lowest	13.9	13.6	14.3	—	13
Average	17.1	15.4	15.1	16.7	—
Highest	18.8	17.7	15.5	—	20
2000					
Lowest	8.9	11.6	12.8	—	9
Average	13.5	12.2	13.1	13.1	—
Highest	14.6	13.5	13.5	—	19
Number of individual forecasts	9	6	5	—	—

NOTE: All forecasts calculate gas on "dry" basis at standard temperature and pressure. Some forecasts include unconventional sources of supply, such as tight sands and Devonian shales; others include only conventional sources.

SOURCE: Office of Technology Assessment, based on data in Jensen Associates, Inc., "Understanding Natural Gas Supply in the U.S.," contractor report to the Office of Technology Assessment, April 1983.

The first two sources of uncertainty are inseparable; the magnitude and character of the resource base have played—and will continue to play—an important role in shaping trends in gas discovery, and these trends in turn provide important clues to gauging the remaining resource base. Consequently, uncertainties in trend interpretation automatically contribute to uncertainties in resource assessment, and resource uncertainties in turn complicate the process of projecting future discovery trends. Similarly, estimating future R/P ratios will depend on projecting discovery trends and understanding the character of the remaining resources.

Each of the three sources of uncertainty will be discussed in turn.

Uncertainty 1: The Gas Resource Base

Many individuals and organizations have published assessments of the natural gas resources of the Lower 48 States. Table 2 presents seven such estimates of the gas resources that remained in the Lower 48 at the beginning of 1983. They range from Hubbert's 244 TCF to the PGC's 916 TCF.

The resource estimates at high and low ends of the range in table 2 have quite different messages for gas production forecasters. At the upper end, the USGS and PGC estimates imply that gas production in this century will be relatively unconstrained because of the resource base magnitude—although this does not rule out the possibility that production may be sharply constrained by the *character* of the remaining resources.* In contrast, estimates at the lower end—Shell, Hubbert, RAND, and Bromberg/Hartigan—imply a serious resource constraint. If these estimates are correct, gas production will decline substantially by the year 2000 (see fig. 1). Therefore, selection of a "best" resource estimate, or narrowing of the range, could conceivably have profound implications for expectations of future gas production.

Table 2.—Alternative Estimates of Remaining Conventional Natural Gas Resources[a] in the U.S. Lower 48 States (as of Jan. 1, 1983)

Source[b] (publication date)	Trillion cubic feet
Hubbert (1980)	244
RAND Corp. (1981)	283
Shell (1977)	320
Bromberg/Hartigan (1975)	340
Wiorkowsky (1975)	663
U.S. Geological Survey (1981)	774
Potential Gas Committee (1983)	916

[a] The term "resources" includes proved reserves, expected growth of existing fields, and undiscovered recoverable resources. In all but the Hubbert estimate, the term does not include gas not recoverable by current or readily foreseeable technology nor gas not recoverable at price/cost ratios similar to today's.

[b] In most cases, the sources for these estimates were assessments of either the ultimately recoverable resource or the undiscovered resource base. The estimates shown are derived by subtracting cumulative production from estimates of ultimately recoverable resource or by adding proved reserves and expected growth of known fields to estimates of the undiscovered resource. Where ranges of resource estimates are given by the source, the estimate in this table is based on the mean value.

SOURCE: Office of Technology Assessment, 1983.

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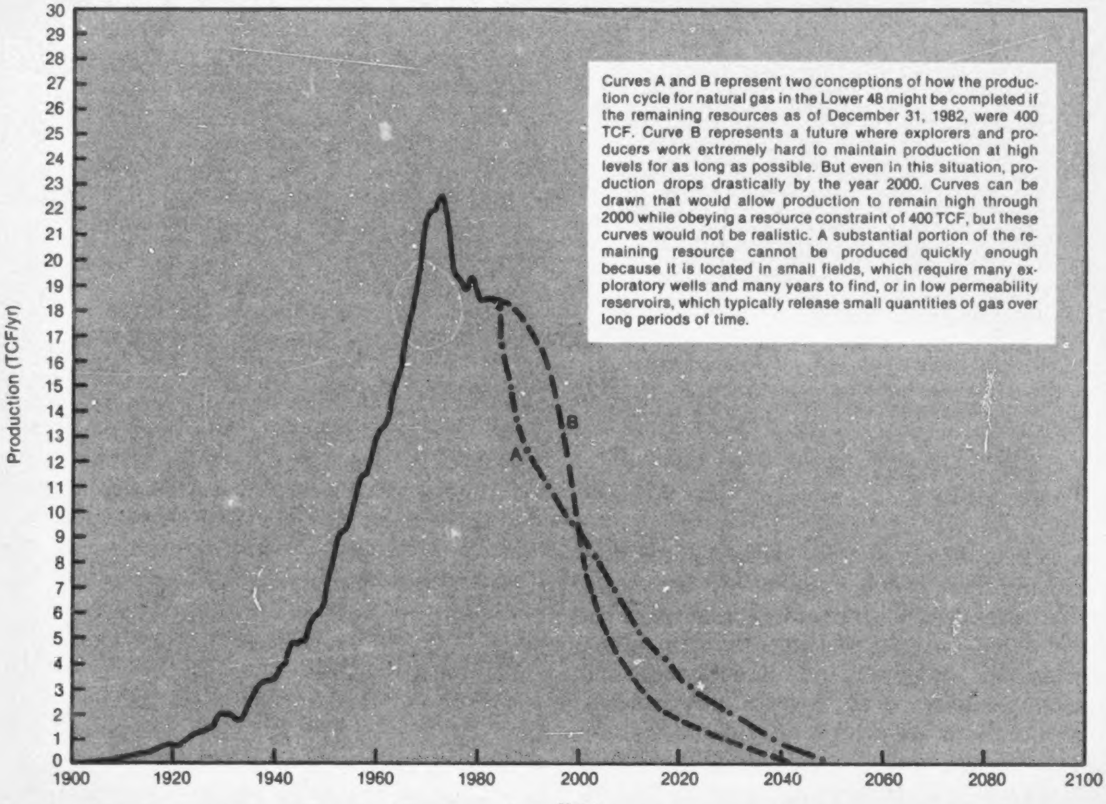
*For example, by their location, depth, degree of contamination, and size distribution of fields and reservoirs.

Figure 1.—Alternative Concepts of the Natural Gas Production Cycle If Remaining Resources = 400 TCF (conventional gas only)



Curves A and B represent two conceptions of how the production cycle for natural gas in the Lower 48 might be completed if the remaining resources as of December 31, 1982, were 400 TCF. Curve B represents a future where explorers and producers work extremely hard to maintain production at high levels for as long as possible. But even in this situation, production drops drastically by the year 2000. Curves can be drawn that would allow production to remain high through 2000 while obeying a resource constraint of 400 TCF, but these curves would not be realistic. A substantial portion of the remaining resource cannot be produced quickly enough because it is located in small fields, which require many exploratory wells and many years to find, or in low permeability reservoirs, which typically release small quantities of gas over long periods of time.

SOURCE: Office of Technology Assessment.

Some of the differences in the estimates may merely be the result of differences in baseline assumptions or boundaries. For example, various assessments may use different assumptions about economic conditions and the state of exploration and recovery technology and may have different geographical boundary conditions. They may or may not include areas currently inaccessible to development, gas from portions of tight sands or other "unconventional" sources that are presently recoverable, or nonmethane components of the gas. Finally, assessments may differ in their definitions of the degree of certainty that should be attached to the estimate. Unfortunately, many assessments do not fully specify their assumptions and definitions, nor is it always clear what effects these assumptions have on the resource estimates. Consequently, it is not possible to "normalize" the various estimates so that they are fully comparable.*

It is OTA's opinion, however, that "normalization" of the various estimates would not eliminate the major differences between them. **OTA finds no convincing basis for the common argument that the area of the Lower 48 States is so intensively explored and its geology is so well known**

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*This does not imply, of course, that *some* normalization cannot be accomplished. For example, PGC has incorporated into its resource estimate quantities of presently recoverable gas in tight reservoirs, whereas both RAND and USGS have tended to exclude this gas from their resource estimates. Consequently, equalizing the conventional/unconventional boundaries of the assessments should reduce the differences between PGC's estimate and those of USGS and RAND.

that there is a substantial consensus on the magnitude of the gas resource base.

Instead, there are several substantive resource base issues that remain unresolved. Among the more important of these are:

The Use of Past Discovery Trends

The extrapolation of past trends in the discovery of natural gas has generally led to pessimistic estimates of the magnitude of the gas resource base. For example, of the resource base assessments examined by OTA, three of the four that used trend extrapolation techniques arrived at estimates that were at least 400 TCF below the USGS median estimate. Acceptance of discovery trend extrapolation as a valid method of resource base assessment, therefore, can yield conclusions about the magnitude of the resource base that are radically different from those that result from using other assessment methods.

The validity of using past discovery trends to estimate the magnitude of the resource base depends on whether the trends are affected more by the nature of the resource base than by the general economic and regulatory climate of the times. Resource "optimists" argue that the disappointing trends in gas discovery of the past few decades have resulted from controlled gas prices, high levels of proved reserves, and limited markets that until recently gave little incentive for high-risk or high-cost drilling. They argue that extrapolation of these trends is invalid because the economic and regulatory conditions that created the trends have changed. Resource "pessimists" argue that the trends are driven mainly by a depleting resource base and are affected only minimally by economic and regulatory conditions; therefore, extrapolation is valid.

In addition to this basic issue, other questions have arisen over the validity and interpretation of resource estimates based on extrapolation of past trends. For example, the accuracy of early records of gas discovery and production is questionable; thus, trend analyses cannot accurately incorporate the entire discovery and production history. Also, the precise economic, technological, geographic, and geologic boundaries of these estimates are difficult to define.

The Potential of Small Fields

Although fields that contain less than 60 billion cubic feet (BCF) of gas have played a minor role in gas production, some analysts believe that small fields will have a major role in the future. The *difference* between optimistic and pessimistic estimates of the future role of small fields may be 100 TCF or more. In OTA's judgment, the arguments on both sides are based primarily on unproven statistical models of field size distributions and on economic tradeoffs that are highly sensitive to gas prices. Only time and further exploration will settle this issue.

New Gas From Old Fields

There are sharp disagreements about the extent to which the resources recoverable from older producing fields may respond to price increases. The mechanisms to increase the "ultimately recoverable resources" of these fields might include lowering abandonment pressures, drilling at smaller spacing to locate gas pockets that otherwise would not be drained, and fracturing the reservoir rock to allow recovery from low-permeability portions of fields. Currently, estimates of the potential increase in recoverable resources range from a few TCF to about 50 TCF.

The Potential of Frontier Areas, Including Deep Gas

Although all resource analysts consider areas such as the deep-water Gulf of Mexico, the deep Anadarko Basin, and the Western Overthrust Belt to have considerable gas potential, considerable disagreement exists over the actual amount of recoverable resources in these areas. Recent indications of engineering problems and rapid pressure declines from deep wells in the Anadarko, coupled with price declines from previous very high levels, raise doubts about whether much of this area's gas resource will be part of the (currently) economically recoverable resource. In the Overthrust Belt, doubts about the magnitude of the resource center on the significance of the failure of explorers to find a giant field over the past 3 to 4 years. Also, areas such as the eastern Gulf of Mexico, the Southeast Georgia Embayment, the Georges Bank, and the Baltimore Canyon have been expensive failures thus far, and their eventual contribution to satisfying U.S. energy requirements is unknown.

Estimates of the recoverable resource potential in the frontier areas vary by up to 100 TCF or more (the USGS and PGC differ by nearly 30 TCF in their assessments of the eastern Gulf of Mexico, alone).

The Potential of Stratigraphic Traps

Stratigraphic traps are barriers to petroleum migration formed by gradual changes in the permeability of sedimentary layers rather than by abrupt structural shifts and deformation of the layers. Because the structural traps are easier to locate, they have been the primary targets for exploration. Some explorers predict that large resources remain to be found in "mature" areas in subtle stratigraphic traps. Although this issue is not settled, the optimistic argument is weakened by observations that numerous stratigraphic traps *have* been found in the Permian Basin and elsewhere and that the extensive drilling in areas that appear to have good prospects for stratigraphic traps should have uncovered most of the larger traps, which generally are extensive in area. Though it may appear more likely than not that most of the remaining undiscovered traps will be small in volume, a possibility exists that larger fields may have remained hidden because of the less effective exploration methods used in the past and drilling that, while extensive, might have clustered in the wrong places or been too shallow.

In addition to these five issues, a level of uncertainty is ever present in the process of estimating the quantity of a resource that cannot be measured directly prior to its actual production. The presence of economically recoverable concentrations of natural gas requires an unbroken chain of events or conditions, the presence or absence of which generally cannot be measured directly. First, adequate amounts of organic material and suitable temperature and pressure conditions for gas formation and preservation must be present. Second, the gas must be free to migrate, and third, an adequate reservoir must be available in the path of migration to contain the gas. Finally, there must be a mechanism to trap the gas, and the trap must remain unbreached until the gas is discovered and produced. These sources of uncertainty account for the various manifestations of risk in natural gas development—the large number of dry holes drilled during exploration, the often huge differences in bids for leases, the multimillion dollar failures of many of the leased areas, **and the continuing disagreements over the size of the remaining resource.**

OTA took into account these general issues, as well as specific problems with individual assessments, in arriving at a plausible range for the amount of remaining gas resources. In OTA's judgment, **a reasonable range for the amount of the remaining conventional natural gas in the U.S. Lower 48 that is recoverable under present and easily foreseeable technological and economic conditions is 400 to 900 TCF as of December 1982.** This range is somewhat narrower than the range displayed in table 2, because OTA considers the low end of the range of resource estimates in the table to be overly pessimistic. However, the general implication of OTA's range is similar to the implication of the range in the table: **The uncertainty in estimating the remaining recoverable gas resource is too high to determine whether or not the resource base magnitude will constrain gas production in this century.** On the other hand, even the more optimistic resource estimates imply that conventional gas production must decline sharply by the year 2020 or before unless technological advances and/or sharp increases in gas prices add substantial quantities of gas to the "economically recoverable" category.

Uncertainty 2: Interpretation and Extrapolation of Discovery Trends

The key to projecting gas production potential to the year 2000 is the successful prediction of future discovery trends and of additions to proved reserves. This focus on the discovery process is necessary because **gas that is already discovered, that is, gas in proved reserves, will be of diminishing importance to production as we move into the 1990's.** Assuming a constant R/P ratio of 8.0, **the current proved reserves of about 169 TCF in the Lower 48 will provide only 2 TCF to total production by the year 2000. All other production**

must come from gas added to proved reserves by the discovery of new fields, the discovery of additional reservoirs in known fields ("new pool discoveries"), the expansion of the areas of known reservoirs ("extensions"), and the reserve changes due to new information or changed economics or technology ("revisions").*

In addition to the effects of resource base uncertainty, interpretation and extrapolation of discovery trends are hampered by a variety of other problems. These include:

Inadequate Discovery Indicators

The interpretation and extrapolation of trends for projecting future reserve additions require the availability of discovery "indicators," such as finding rates for new field wildcats, that can be interpreted in a relatively unambiguous fashion. OTA found that **essentially all indicators available from public data that describe the natural gas discovery process have ambiguous interpretations** because the data are highly aggregated and are dependent on a wide variety of factors. For example, the "exploration" whose success is being measured by a finding rate actually includes several kinds of exploratory drilling, from high-risk, high-return drilling that searches for giant fields in new geologic horizons, to low-risk, low-return drilling that clusters around a new strike or redrills already explored areas that have grown more attractive with price increases. **Because the proportions of different varieties of exploratory drilling may change substantially with changing market conditions, interpreting trends in finding rates and other indicators of exploration success is difficult. This is especially true if the data are highly aggregated geographically.**

Uncertainty About the Future Growth of New Fields

At least three-quarters of past additions to proved gas reserves have come from the discovery process that *follows* the discovery of new fields. This secondary discovery process seeks new reservoirs in the field and the expansion of known boundaries of already discovered reservoirs. The extent to which recently found fields and future fields will grow in the same manner as fields found in the past is critical to future reserve levels and thus to future production. There has been speculation that the decline in finding giant fields—which require many years and discovery wells to develop fully—and the addition to the reserve base of increasing numbers of very small fields will lead to significant declines in field growth. **If the new fields discovered in the past few years do not grow at near-historic levels, then reserve additions due to new pool discoveries and extensions will decline substantially from recent levels, even if new field discoveries can stay at their present higher rate. OTA believes that such a decline in field growth is plausible, but verification requires additional analysis at the individual field level and continued observation of field growth trends.**

Difficulties in Interpreting the Recent Surge in Reserve Additions

After the decade 1969-78, during which additions to gas reserves in the Lower 48 States averaged less than 10 TCF/yr,* reserve additions have surged to over 20 TCF** in 1981 and are expected to be nearly as high in 1982. This surge has been the centerpiece of arguments for future high production levels.

In OTA's judgment, **it is not clear whether or not the recent high rates of additions to proved gas reserves are sustainable, even if drilling rates rebound to the levels achieved before the recent slump.** For example, 13.5 TCF of the total 1981 additions came from secondary discoveries, that is, extensions and new pool discoveries. Normally, such a surge in secondary discoveries would be preceded a few years earlier by an increase in new field discoveries, because recently discovered fields provide the most promising target areas for secondary discoveries. However, the number of new fields discovered in the 5 years before 1981 did not seem high enough to be the primary cause of 1981's high secondary discoveries. Alternative or additional causes of the recent increases in secondary discoveries could include: an acceleration in the normal pace of field growth (e.g., growth that normally might occur over a 20-year period instead is achieved in 5 years, yielding a short-term increase in "per year" reserve additions followed by a dropoff in later years); the rapid development of a limited inventory of low-risk drilling prospects that had been identified in prior years but ignored because of unfavorable economic conditions; and a substantially increased growth potential for the current (and future) inventory of discovered fields because of the expansion of recoverable resources with higher prices and improved exploration and production technology. The first two causes would imply that secondary discoveries will decline sharply in the near future as the limited inventory of prospects is used up; the third cause implies that high levels of secondary discoveries might be sustainable. In fact, it is likely that all three causes played a role in the recent surge, but their relative share is uncertain.

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*This last category of reserve additions may be negative.

*As reported by the American Gas Association.

**As reported by the Energy Information Administration. The American Gas Association, the major source of reserve data prior to 1977, no longer publishes detailed information on reserve additions.

Similarly, it is not clear to what extent recent higher reported rates of new field discoveries are caused by any (or all) of the following factors: an increased willingness of explorers to go after riskier prospects; the exploitation of a limited inventory of low-risk prospects identified by past exploration; an increase in the number of economically viable fields, caused by improved technology and higher prices; and recent changes in reserve reporting methodologies.*

OTA projected a plausible range of future additions to Lower 48 gas reserves by trying to account for uncertainties about the resource base magnitude, the resource characteristics most likely to affect the discovery process, and the actual causes of past and recent discovery trends. OTA concluded that, under the assumed demand/price/technology conditions, **multiyear average levels of total reserve additions could range from 7 to 8 TCF/yr to 16 to 17 TCF/yr or higher by 1986.** Projected average values for individual components of reserve additions are:

New field discoveries	1.5-3.5 TCF/yr
Extensions and new pool discoveries	6.0-11.0 TCF/yr
Revisions	0-+2.0 TCF/yr

Uncertainty 3: Production From Proved Reserves—The R/P Ratio

The reserves-to-production (R/P) ratio reflects the rate at which gas is being withdrawn from discovered reservoirs; consequently, it represents the analytical link between projections of new discoveries and forecasts of gas production. There are very large differences in R/P ratios from field to field, depending on the age, geology, location, and contract terms of the gas production. **OTA projects that the aggregate average R/P ratio for the Lower 48 may range from 7.0 to 9.5 by the year 2000**, assuming that economic conditions are generally favorable to production (in other words, in contrast to today's gas "bubble"). The R/P ratio in 1981 was 9.0, the result of a long and relatively steady decline from a level of 30 in 1946.

Although the R/P ratio is sensitive to economic factors, such as actual and expected gas prices and interest rates, technical factors will also play an important role in determining this ratio in the future. Gas in low-permeability reservoirs will play an increasing role in reserves, tending to push up R/P levels. The importance of offshore development will affect national R/P levels because offshore fields have typically been exploited very quickly. As more and more gas is produced in frontier areas with very high drilling costs, difficult tradeoffs will have to be made between the desire for rapid production and the costs of drilling additional development wells. The rate of adding new reserves—which itself is highly uncertain—will determine the average age of the United States' producing fields, an important factor in production rates. Uncertainty in these factors makes it difficult to predict whether future average R/P levels will increase or decrease from today's level.

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*The American Gas Association reported U.S. reserve additions until 1979. The Energy Information Administration began reporting reserve additions in 1977 using a different data collection and analysis procedure, and modified this procedure in 1979.

Summary of Assumptions and Conditions Underlying OTA's Projections

Table 3 summarizes the assumptions and conditions that lead to the low and high ends of OTA's projection for conventional gas production for the Lower 48 States in the year 2000.

Table 3.—Bases for OTA's Projections of Natural Gas Production—Baseline Assumptions: Good Market Conditions, Readily Foraseeable Technology

	9 TCF/yr in 2000	19 TCF/yr in 2000
1. Magnitude of remaining resources:	400 TCF	900 TCF
2. Character of remaining resources:	Remaining exploration plays[a] are only of moderate size; few surprises. Some major potential remaining in frontier areas but deep resource is disappointing. Small fields are only a minor source of additional gas because of economics and/or smaller numbers than a straight-line extrapolation would predict. Resource in stratigraphic traps is disappointing; remaining growth of old fields is moderate.	High potential for major new exploration plays. Deep resource is both plentiful and economically accessible. Small fields may play an important role, but many large fields still remain. Resource remaining in mature areas, much of it in subtle stratigraphic traps, is substantial. Remaining growth of old fields is high.
3. Causes of past trends in gas discovery:	Magnitude and character of the resource base were the primary causes.	Artificially low prices and rigid regulation were as important as the resource base.
4. Meaning of recent surge in reserve additions:	A temporary response to higher prices, drilling a backlog of easy but formerly marginal prospects—not sustainable. Possibly also caused by a change in reporting practices.	An indication of a real turnabout in gas discovery; the opening up of major new exploration horizons, readily sustainable if exploratory drilling revives.
5. Projected rate of future annual reserve additions:	Total: Declines to 7.5 TCF by 1986:	Maintained at 16.5 TCF or above for the next few decades:
	New field discoveries: 1.5 TCF	3.5 TCF
	Extensions and new pool discoveries: 6.0 TCF by 1986	11.0 TCF
	Revisions: 0	+2.0 TCF
6. R/P Ratios:	9.5 by 2000, predicated on lower permeability reserve additions, difficult production conditions.	7.0 by 2000, predicated on high demand coupled with generally favorable physical conditions.

[a] Play—An exploratory campaign based on a cohesive geologic idea.

SOURCE: Office of Technology Assessment, 1983.

OTHER SOURCES OF LOWER 48 SUPPLY

Aside from domestic conventional gas production, gas consumers in the Lower 48 States may have access to other sources of supply, including production from so-called unconventional sources (tight sands, coal beds, gas in geopressurized aquifers, and Devonian shales); pipeline imports from Alaska, Canada, and Mexico; LNG imports from a variety of gas-producing nations throughout the world; and synthetic natural gas from coal and biomass. The potential supply from unconventional sources will be discussed in a future report of OTA's U.S. Natural Gas Availability study. OTA previously discussed synthetic natural gas in a report released in 1982.[1]

The United States currently imports about 0.9 TCF of gas per year, most of it from Canada. Because each of the four sources of gas import potential have substantial and accessible resources, **imports could theoretically satisfy a major portion of U.S. gas requirements later in this century and beyond. However, each of the import sources, like future domestic production, is subject to considerable uncertainty.** High transportation costs are a particular problem for Alaskan gas and LNG, creating the need, at a minimum, to accept wellhead prices substantially below equivalent oil prices. Similar problems exist for Canadian and Mexican gas. Canadian and Mexican exports to the United States must also compete with the uncertain future requirements of their own domestic gas users. Based on available studies, **the expected import potential from Canada, Alaska, and Mexico may range from 1.0 to 7.4 TCF in the year 2000, with Canada being the most certain large contributor. LNG imports are even less predictable.** Finally, OTA projects synthetic natural gas from coal to range from 0 to 1.6 TCF/yr by the year 2000.

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[1] *Increased Automobile Fuel Efficiency and Synthetic Fuels: Alternatives for Reducing Oil Imports* (Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-185, September 1982).

Chapter 2

Introduction

Chapter 2

Introduction

The passage of the Fuel Use Act in 1977, which sharply limited the allowed uses of natural gas in the industrial and electric utility sectors, took place in an atmosphere of extreme pessimism about future gas supplies. An Electric Power Research Institute report published in that year stated that:

> Today almost every important supply indicator points ominously to the fact that the Nation's ability to meet present and future demands for natural gas may be deteriorating rapidly and will continue to do so unless aggressive and innovative measures to rectify the situation are implemented immediately.[1]

These pessimistic predictions were based partly on short-term problems—periodic curtailments that caused considerable hardship to industry and occasionally even to public facilities and to the commercial sector. They were also based, however, on disturbing long-term trends, such as a declining finding rate for new gasfields and, starting in the late 1960's, the ominous and apparently unstoppable decline of proved reserves (fig. 2).

Since 1977, the national perception of future natural gas availability has changed, for several reasons, to one of relative optimism. First, short-term supply is now in a state of surplus; a large gas "bubble," or surplus deliverability, estimated to be as high as 2 trillion cubic feet (TCF) per year,[2] has been caused by a combination of energy conservation, recession-induced reductions in industrial activity, and industrial fuel-switching from gas to oil because of declining oil prices and increased gas prices. At the same time, reserve additions have apparently rebounded from the depressed levels of the 1970's to over 20 TCF in 1981.[3] Also, the U.S. Geological Survey (USGS) and the Potential Gas Committee (PGC) have each recently confirmed their earlier estimates of the remaining recoverable resources in the Lower 48 States:[4] the latest USGS estimate implies that about 770 TCF of gas remain as of January 1983, while the PGC estimate implies an even more optimistic 910 TCF.[5] These estimates, which do *not* include gas that could be recovered with completely new technologies and/or substantially higher prices, both exceed the amount of gas that the United States has already produced during the entire history of its gas use.

As a result of these optimistic signs, much of the natural gas industry believes that gas demand has replaced supply as a critical issue, and some industry organizations are even claiming that supply from all sources could be sufficient to allow a substantial expansion of U.S. gas consumption in the next few decades.[6] Also, Congress is reexamining the legislation governing the U.S. natural gas market.

In reaction to this changing outlook for U.S. natural gas supply, the House Committee on Energy and Commerce and its Subcommittee on Fossil and Synthetic Fuels, supported by the Subcommittee on Energy Research and Development of the Senate Committee on Energy and Natural Resources, asked OTA to conduct a study of domestic (Lower 48 States) natural gas availability over the next few decades. The overall study will examine both conventional and unconventional sources of natural gas (the unconventional sources include coal-bed methane, tight sands, Devonian shale, and geopressurized aquifers), review current estimates of resource bases and production

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[1] R. Ciliano, et al., *A Comparative State-of-the-Art Assessment of Gas Supply Modeling*, EPRI report EA-201, February 1977.

[2] "Oil Finds of 108 Billion bbl Seen in '80's," *Oil & Gas Journal*, Sept. 27, 1982, p. 140.

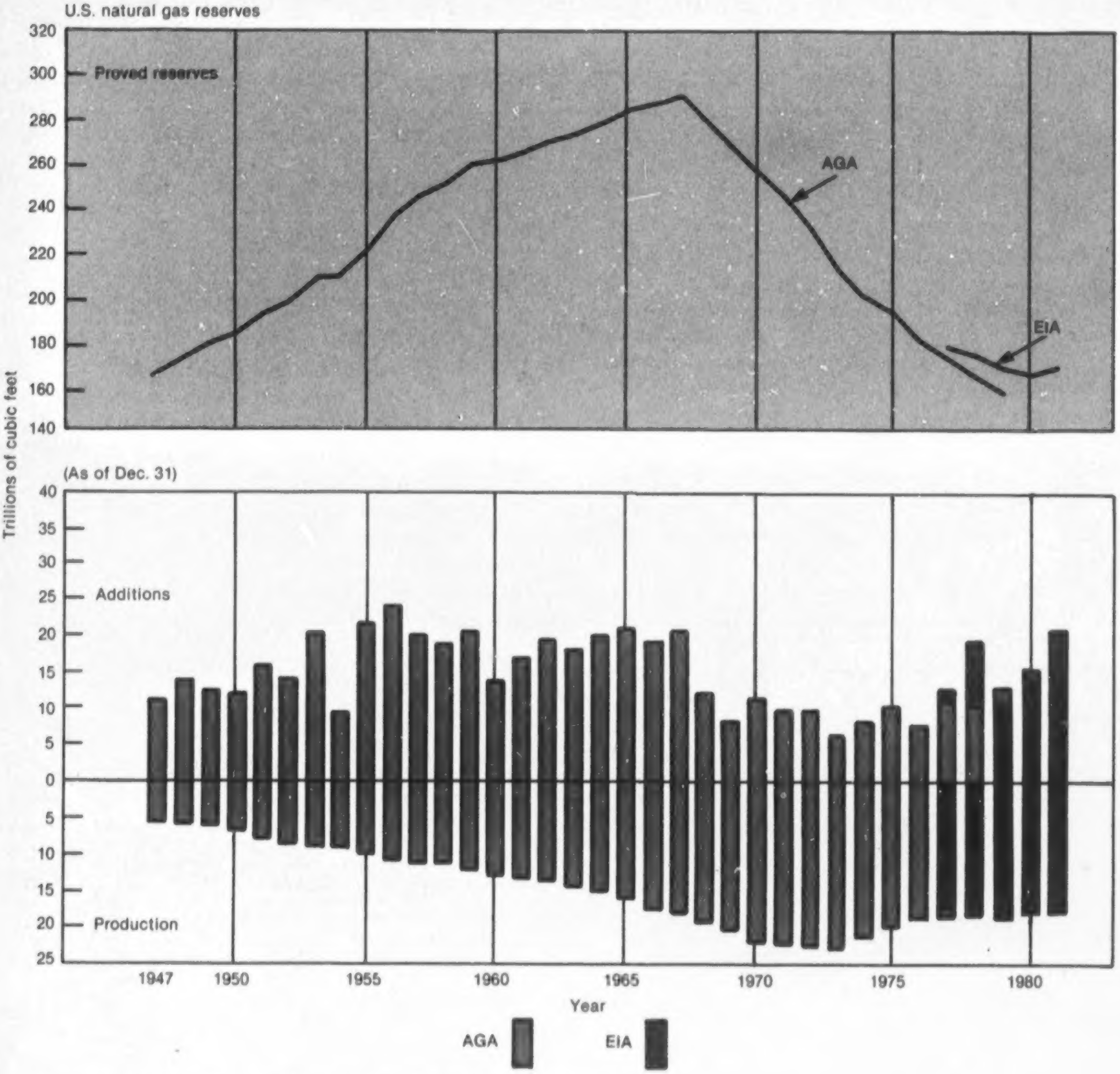
[3] Executive summary and selected summary tables from "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves," *1981 Annual Report*, prepublication draft, Aug. 30, 1982, Energy Information Administration (EIA), U.S. Department of Energy. Because the EIA data series appears to differ somewhat from the earlier American Gas Association data (EIA began in 1977), the interpretation of the recent higher reserve additions is somewhat controversial.

[4] B. M. Miller, et al., *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States*, USGS Circular 725, 1975; and Potential Gas Committee, *Potential Supply of Natural Gas in the United States (as of December 31, 1980)* (Golden, Colo.: Potential Gas Agency, Colorado School of Mines, May 1981).

[5] G. L. Dolton, et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, Geological Survey Circular 860, 1981; and Potential Gas Agency, *News Release—February 26, 1983*.

[6] For example, see *The Gas Energy Supply Outlook: 1980-2000*, American Gas Association, January 1982.

Figure 2.—Natural Gas Production: Additions to Reserves, and Total Reserves of the Lower 48 States



SOURCE: American Gas Association, *The Gas Energy Supply Outlook: 1980-2000*, January 1982.

potentials, and examine key technical issues that will affect the future development of those sources.

This technical memorandum presents OTA's evaluation of the prospects for future supplies of conventional natural gas.* It focuses first on an assessment of the conventional gas resource base, and second, on an evaluation of production potential for the mid to long term—10 to 20 years and beyond. The size of the resource will obviously play a critical role in long-term supply and an important but less widely understood role in the midterm supply.

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*This material will form one section of OTA's final report on U.S. Natural Gas Availability. The memorandum is being released early in view of the current congressional debate on natural gas.

The memorandum is oriented primarily towards examining the role played by *technical* uncertainties in estimating future gas availability. Specifically, the memorandum examines the recoverable resource base and future gas production potential under the following conditions:

- *Demand for gas is high,* implying that explorers and producers do not curtail their activities because of fear that their gas will not be marketable. The current gas "bubble" is assumed to end shortly and not to reoccur, and drilling rates are assumed to rebound to levels achieved before the recent slump. Consequently, "pessimistic" scenarios examined in this study reflect only pessimism about technical prospects for gas discovery and production and do not reflect the possibility that low gas demand may drive down discovery rates and production.
- *Average wellhead prices do not change grossly from today's levels,* implying primarily that gas sources that today are unequivocally outside of the "economically recoverable" range are excluded from OTA's resource estimates and projections of future production potential.
- *New technologies* that are not readily foreseeable extensions of existing technologies *are not considered* in the analyses.

This orientation clearly requires that the estimates of resources and production potential presented in the report be interpreted carefully. For example, OTA's assumptions about price and technology are likely to yield conservative estimates of gas resources and production potential. Historically, the recoverable resource bases for essentially all nonrenewable resources have expanded as prices rose and new recovery technologies were developed (see ch. 4, "Resource Base Concepts"). This has certainly been the case for the gas resource base in the past, and will undoubtedly also be the case in the future. However, the extent and timing of future expansion of gas resources is extremely difficult to predict.

In addition, as noted, a continuation of low gas demand would tend to change future production potential relative to that projected only on the basis of the *technical* potential. A lack of markets will discourage exploration, new pipeline development, and other determinants of future production potential, although simultaneously it will slow the drawing down of existing proved reserves, the "ready inventory" for future production.

The remainder of the memorandum is organized in the following fashion:

- *Chapter 3: Natural Gas Basics* presents a brief review of basic natural gas terminology and concepts.
- *Chapter 4: The Natural Gas Resource Base* reviews resource assessment methodologies, describes and critiques several specific gas resource assessments, evaluates a number of critical resource issues, and presents OTA's conclusions about the magnitude of the remaining resource base.
- *Chapter 5: Gas Production Potential* describes four approaches used by OTA to evaluate the gas production potential to the year 2000, and presents OTA's conclusions about this potential.
- *Chapter 6: Other Gas Sources—Summary* briefly reviews the prospects for additional sources of supply to the Lower 48 States—liquefied gas imports and pipeline imports from Alaska, Canada, and Mexico.

Chapter 3

Natural Gas Basics

Chapter 3

Natural Gas Basics

This chapter briefly describes basic theories and terminology used within the report—i.e., it briefly describes what natural gas is, how it is formed, how it is found and subsequently produced, and how discoveries are reported. Words in boldface are defined in the glossary at the end of the technical memorandum. *Readers familiar with basic terminology and concepts of natural gas supply may wish to skip this section.*

WHAT IS NATURAL GAS?

As its name implies, natural gas is a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in subsurface reservoirs within the Earth's crust. Methane (CH_4), a light hydrocarbon, is the primary constituent of natural gas and of principal interest to the energy industry. Associated heavier hydrocarbons such as ethane, propane, and butane and impurities such as water, hydrogen sulfide, and nitrogen occur with the methane. If the concentrations of these other constituents render the gas unmarketable, they must be removed prior to use.

HOW DOES NATURAL GAS FORM?

There is no universally accepted explanation of how natural gas formed. Most hydrocarbon deposits of significant size occur in **sedimentary basins,** however, and are thought to have originated from the decay and alteration of organic matter. Hundreds of millions of years ago, seas that covered a large portion of the land exposed today were inhabited by tiny plants and animals that, upon dying, sank to the bottom and were buried under layers of sediment. In areas of rapid **sedimentation,** organic decay was accompanied by high pressures and temperatures which, over millions of years, effectively "cooked" the organic material into **petroleum** (oil and natural gas). Hydrocarbons could also have been formed by other processes: by the **anaerobic** (without oxygen) digestion of organic materials by bacteria, and inorganically by the reduction of inorganic carbon and its oxides at high pressures and temperatures deep within the Earth. The quantity of recoverable gas thought to have originated by these processes is generally felt to be small, but some controversy still exists, especially concerning the inorganic processes.

Temperature and pressure conditions have a critical role in determining the physical state of the hydrocarbons that result. Natural gas may be found at all depths, but it originated mostly in rocks subjected to particularly high temperatures and pressures over long periods of time. It generally is the only hydrocarbon present at depths beyond 16,000 ft. Liquid hydrocarbons occur at shallower depths, from about 2,500 to 16,000 ft, where lower temperatures are characteristic.[1] Most crude oil is found between 6,500 and 9,000 ft, with light hydrocarbon liquids occurring at depths greater than 9,500 ft.[2]

WHERE IS NATURAL GAS FOUND?

Petroleum accumulations occur as **reservoirs** or **pools**—not in caverns or large holes in a rock mass but in the minute pore spaces between the particles that compose the rock. The greater the amount of pore space in the rock (**porosity**), the larger the quantity of gas or oil that may be contained within it. Pools often occur together in a **field**, and multiple fields in similar geologic environments constitute a **province.**

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[1] H. Douglas Klemme, *Geothermal Gradients, Heat Flow, and Hydrocarbon Recovery. Petroleum and Global Tectonics* (Princeton and Landon: Princeton University Press, 1975), p. 260. Cited in Jensen Associates, Inc., *Understanding Natural Gas Supply in the U.S.,* contractor report to OTA, April 1983.

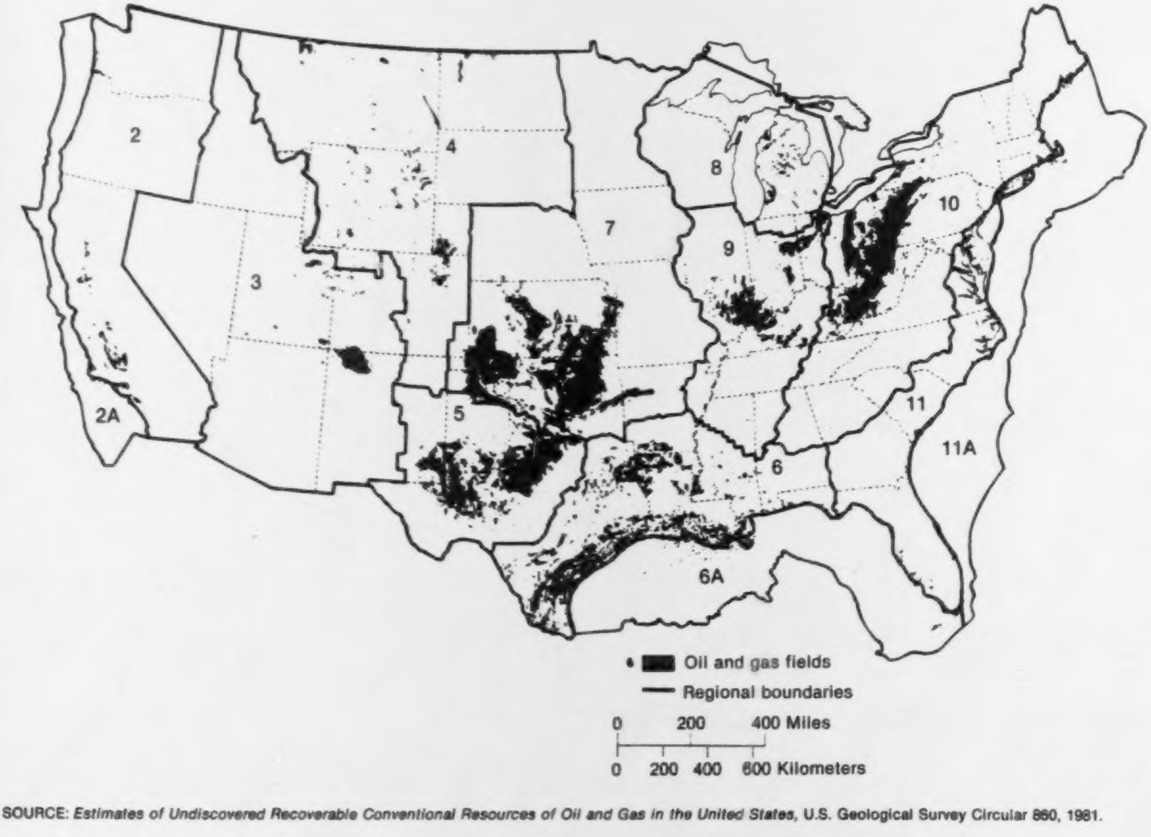
[2] B. P. Tissot and D. H. Welte, *Petroleum Formation and Occurrence* (New York: Springer-Verlag, 1978), p. 202. Cited in Jensen Associates, Inc., op. cit.

Gas occurs separate from (**nonassociated gas**) and together with oil. When together, it occurs in solution with the oil (**dissolved gas**) or as free gas (**associated gas**), in a gas cap when no more gas can be held in solution under the pressure and temperature conditions of the reservoir.

The search for hydrocarbon accumulations is narrowed by the requirement for the presence of organic material in the sediment at the time of burial. Sedimentary basins are the areas most likely to have contained the organic-rich rocks—**source rocks**—required for petroleum formation. Sedimentary rocks compose about 75 percent of the exposed rocks at the surface, but only 5 percent of the Earth's crust (outer 10 miles) . The known oil- and gas-bearing areas in the United States are identified in figure 3.

Although source rocks are required for petroleum formation, commercial petroleum accumulations are not usually found in the source rock. Source rocks are generally too impermeable, meaning the texture of the source rock does not allow petroleum to flow easily through the pores to a producing well. Typically, after the petroleum was formed, the gases and fluids (oil and **formation water**) migrated from the source bed to a more **permeable** rock, called the **"reservoir rock"** (this process is called "primary migration"). The fluids moved in the path of least resistance (or

Figure 3.—Known Oil- and Gas-Bearing Areas in the Lower 48 States

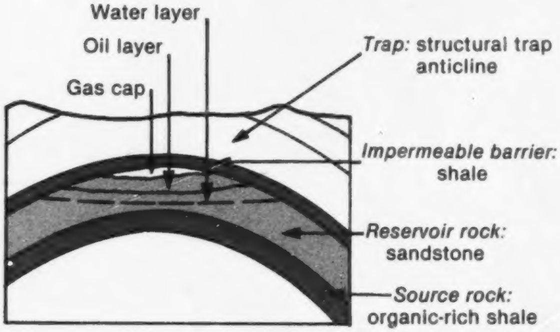


SOURCE: *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.

highest permeability) and continued migrating within the reservoir rock (secondary migration) until an impermeable barrier was encountered, which prohibited further migration into adjacent or overlying rock units or **formations**. The petroleum then migrated further along the barrier to a place of accumulation, called a **trap**—usually located at the highest point where the reservoir rock contacts the more impermeable, barrier rock. The four requirements for a hydrocarbon accumulation—a source rock, reservoir rock, impermeable barrier rock, and trap—are illustrated in figure 4.

There are three basic types of petroleum traps: **structural**, **stratigraphic**, and **combination** (see fig. 5). Structural traps are formed by earth movements that deform or rupture rock strata, thereby creating favorable locations for hydrocarbons to accumulate. Such structural features as faults and **anticlines** create enclosures that serve as loci for migrating petroleum. Stratigraphic traps are created by permeability and porosity changes characteristic of the alternating rock layers that result from the sedimentation process. In stratigraphic traps, pinched-out beds, sandbars, or reefs serve as reservoirs for migrating petroleum. Combination traps result from both structural and stratigraphic conditions. An example of a combination trap is one that results from a salt dome intrusion during deposition that alters the thickness of the strata deposited.

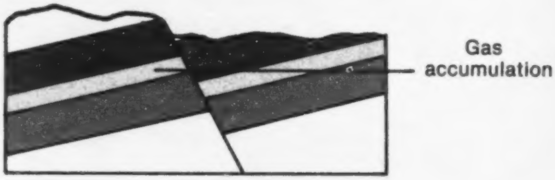
Figure 4.—Four Requirements for Petroleum Accumulation


Water layer
Oil layer
Gas cap
Trap: structural trap anticline
Impermeable barrier: shale
Reservoir rock: sandstone
Source rock: organic-rich shale

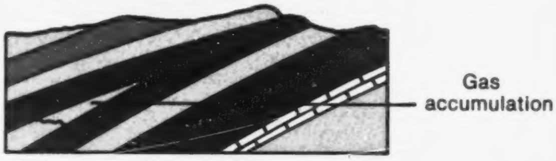
SOURCE: Office of Technology Assessment.

Figure 5.—Trapping Mechanisms

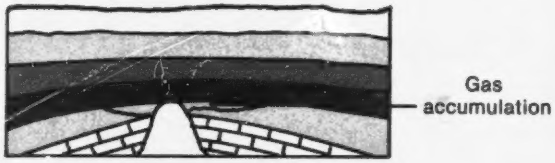
Structural trap—fault



Stratigraphic trap—pinched-out bed



Combination trap—salt intrusion



SOURCE: Office of Technology Assessment.

HOW IS NATURAL GAS DISCOVERED?

Before an understanding of subsurface geology was acquired or rules of petroleum occurrence were established, petroleum discoveries were based on surface seeps, knowledge gained from water-well drilling, and luck. Today there are a variety of concepts, exploration methods, and instruments available to help geologists locate subsurface hydrocarbon accumulations.

The type of exploration techniques used varies between sites and depends on how much is known about the area being explored. In areas where little is known about the subsurface, reconnaissance techniques—which provide limited information over a large area—are used to identify favorable areas that warrant more detailed investigation. Satellite and high-altitude imagery sometimes reveals large geologic features or trends that are surface expressions of subsurface geologic structure. Magnetic and gravity surveys detect changes in the magnetic or density properties of the Earth's crust and are also used to infer subsurface structure.

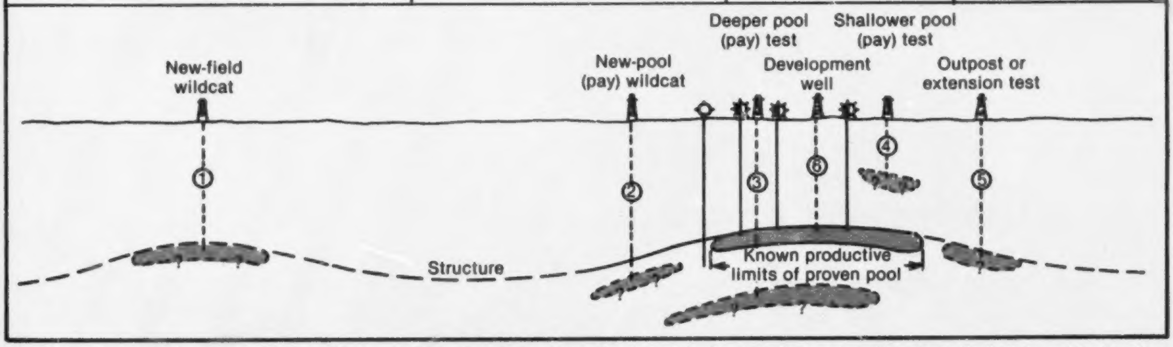
Once a promising area has been identified, more detailed, higher resolution exploratory techniques are used to locate individual **prospects** for the drill and to project conceptually related groups of prospects, or **plays.** The seismic reflection method, which measures and interprets the reflections of sound waves off of geologic discontinuities, is particularly effective for providing detailed subsurface information. Drilling is the final stage of the exploratory effort and the only sure way to determine if hydrocarbon-filled reservoirs exist in the subsurface.

In some basins, drilling may be performed so cheaply that predrilling exploration expenditures for seismic surveys and other analyses are not justified. These shallow areas are becoming increasingly scarce, and the role of predrilling exploration analysis is increasing in importance, particularly in frontier areas. If these high-cost areas are to be drilled, operators must be relatively sure that the drilling expense is justified.

The degree of risk involved in drilling depends on how much is known about the subsurface at the drill site. As illustrated in figure 6, a classification scheme has been established to categorize the exploratory wells based on their relationship to

Figure 6.—AAPG and API Classification of Wells

<table>
<tr><th colspan="4" rowspan="2">Objective of drilling</th><th rowspan="2">Initial classification when drilling is started</th><th colspan="4">Final classification after completion or abandonment</th></tr>
<tr><th colspan="2">Successful</th><th colspan="2">Unsuccessful</th></tr>
<tr><td colspan="4">Drilling for a new field on a structure or in an environment never before productive</td><td>1. New-field wildcat</td><td colspan="2">New-field discovery wildcat</td><td colspan="2">Dry new-field wildcat</td></tr>
<tr><td rowspan="3">Drilling for a new pool on a structure or in a geological environment already productive</td><td rowspan="3">New pool tests</td><td colspan="2">Drilling outside limits of a proved area of pool</td><td>2. New-pool (pay) wildcat</td><td rowspan="3">New-pool discovery wells *(sometimes extension wells)*</td><td>New-pool discovery wildcat</td><td rowspan="3">Dry new-pool tests</td><td>Dry new-pool wildcat</td></tr>
<tr><td rowspan="2">Drilling inside limits of proved area of pool</td><td>For a new pool above deepest proven pool</td><td>3. Deeper pool (pay) test</td><td>Deeper pool discovery well</td><td>Dry deeper pool test</td></tr>
<tr><td>For a new pool below deepest proven pool</td><td>4. Shallower pool (pay) test</td><td>Shallower pool discovery well</td><td>Dry shallower pool test</td></tr>
<tr><td colspan="4">Drilling for long extension of a partly developed pool</td><td>5. Outpost or extension test</td><td colspan="2">Extension well *(sometimes a new-pool discovery well)*</td><td colspan="2">Dry outpost or dry extension test</td></tr>
<tr><td colspan="4">Drilling to exploit or develop a hydrocarbon accumulation discovered by previous drilling</td><td>6. Development well</td><td colspan="2">Development well</td><td colspan="2">Dry development well</td></tr>
</table>



SOURCE: Lahee classification of wells, as applied by the Committee on Statistics of Drilling of the American Association of Petroleum Geologists, and the American Petroleum Institute. Developed by Frederic H. Lahee in 1944.

known petroleum discoveries. There are three basic kinds of exploratory well. A **new field wildcat** is a well drilled in search of a new field, that is, in a geologic structural feature or environment that has never been proven productive. New field wildcats generally have the greatest associated risk because they are drilled based on the least preexisting knowledge. **New pool wildcats**—in search of pools above (shallower), below (deeper), or outside the areal limits of already known pools—are generally less risky because the field in which they are drilled has been proven productive. **Outpost and extension tests** are drilled to determine the bounds of known pools. **Development wells** are the least risky because their primary function is to extract the petroleum from the already proven pools; they are not exploratory wells.

When an exploratory well encounters petroleum, the quantity of proved reserves is estimated, and the commercial viability of the reservoir evaluated. Proved reserves are determined by analyzing actual production data or the results of conclusive formation tests. The proved area is the area that has been delineated by drilling and the adjoining area not yet drilled but judged as economically producible based upon available geologic and engineering data. Because of its conservative nature, the initial estimate of proved reserves based on a field's discovery well is generally significantly smaller than the quantity of gas ultimately recovered from the field. Wells drilled in subsequent years may increase the proved area of the reservoir or lead to the discovery of additional reservoirs within the field.

Each year, the sum of reserve additions attributed to the three types of exploratory wells are reported by the Energy Information Administration (EIA) as "new field discoveries" (these are the *initial*, first-year estimates of a new field's proved reserves), "extensions," and "new reservoir (pool) discoveries in old fields." (In this memorandum, this last category of reserve additions is called *new pool discoveries*, for brevity.) Another reporting category, "revisions," includes those reserves that are added or subracted because of new information about old fields, for example, an indication that the fields will be drawn down to lower pressures because of a gas price increase, pressure histories during production that deviate from the expected values, or the use of measures to increase recovery. Another category, "Net of Corrections and Adjustments," reports reserve changes from corrections of previous arithmetic or clerical errors, adjustments to previously reported gas production volumes, late reporting of reserve additions, and so forth.* Table 4 shows the changes in U.S. gas reserves from 1977 to 1981 as reported in the EIA yearly report, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves—Annual Report*.

Table 4.—Estimated Total U.S. Proved Reserves of Natural Gas—1977-81

Year	Net of corrections & adjustments (1)	Revision increases (2)	Revision decreases (3)	Extensions to old reservoirs (4)	New reservoir discoveries in old fields (5)	New field discoveries (6)	Total discoveries[b] (7)	Production (8)	Proved reserves[b] 12/31 (9)	Net change from prior year (10)
Natural gas[c]										
1976 ..	—	—	—	—	—	—	—	—	213,278[e]	—
1977 ..	−20[d]	13,691	15,296	8,129	3,301	3,173	14,603	18,843	207,413	−5,865
1978 ..	2,429	14,969	15,994	9,582	4,579	3,860	18,021	18,805	208,033	620
1979 ..	−2,264	16,410	16,629	8,950	2,566	3,188	14,704	19,257	200,997	−7,036
1980 ..	1,201	16,972	15,923	9,357	2,577	2,539	14,473	18,699	199,021	−1,976
1981 ..	1,627	16,412	13,813	10,491	2,998	3,731	17,220	18,737	201,730	2,709

NOTE: "Old" means discovered in a prior year. "New" means discovered during the report year.

[a] Column 4 + Column 5 + Column 6.

[b] Prior year Column 9 + Column 1 + Column 2 − Column 3 + Column 7 − Column 8.

[c] Billion cubic feet, 14.73 psia, 60° F.

[d] Consists only of reported corrections.

[e] Based on following year data only.

SOURCE: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves—1981 Annual Report*, DOE/EIA-0216 (81), August 1982.

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*EIA began its data series in 1977. The American Gas Association and American Petroleum Institute also published reserve statistics in basically the same format (without a "corrections and adjustments" category) from 1966 to 1979, and in a somewhat different format from 1947 to 1965.

HOW IS NATURAL GAS PRODUCED?

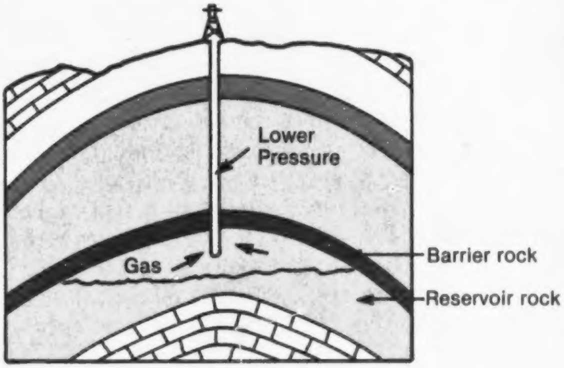
The way in which gas is produced depends on the properties of the reservoir rock and whether the gas occurs by itself or in association with oil. As illustrated in figure 7, hydrocarbons in the reservoir rock migrate to the producing well because of the pressure differential between the reservoir and the well. How readily this migration occurs is a function of the pressure of the reservoir and the permeability of the reservoir rock.

Production will continue as long as there is adequate pressure in the reservoir to propel the hydrocarbons toward the producing well. If gas is the only propellant, the reservoir pressure decreases as the gas is extracted and is eventually no longer sufficient to force the hydrocarbons toward the well. In a water-drive reservoir, water displaces the hydrocarbons from the pores of the reservoir rock, maintaining reservoir pressure during production and improving the recoverability of the hydrocarbons. In most reservoirs, gas recovery is high, generally greater than oil recovery. A "typical" recovery value of 80 percent is often cited, but the basis for this value is not firm, and recovery is certainly less in many reservoirs under current conditions. When gas occurs in association with oil, it can be reinjected into the reservoir to maintain pressure for maximum oil recovery. Gas is also reinjected when there are no pipeline facilities available to transport it to market.

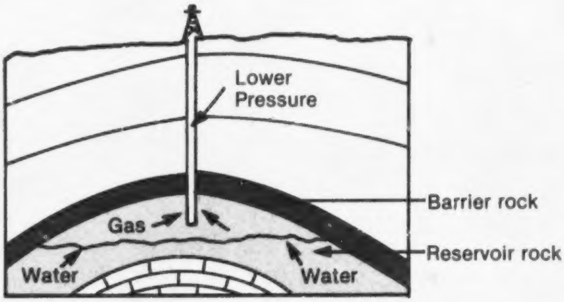
Once the raw gas is produced from the well, it is gathered with production from other nearby wells and processed to remove natural gas liquids and impurities that could cause problems in the pipeline. The gas is then sent by pipeline to local gas utilities who sell it to the end-user. In some instances, such as those involving large industrial users, the pipeline will sell directly to the end-user and bypass the local gas utility.

Figure 7.—Production Mechanics

Gas drive mechanism



Gas and water drive mechanism



SOURCE: Office of Technology Assessment.

Chapter 4

The Natural Gas Resource Base

The Natural Gas Resource Base

> About the only thing that any estimator can say with certainty about his (resource) estimate is that it is wrong.
>
> Richard P. Sheldon
> U.S. Geological Survey

The focus of this technical memorandum is on U.S. natural gas availability for the next few decades—and, specifically, on the gas supply that can be provided by production in the Lower 48 States. Some analysts have claimed that the resource base is not an important constraint to gas supply during this period because the U.S. Geological Survey (USGS) estimated resource represents over 40 years of supply at current production levels, which does not count huge resources of unconventional gas (e.g., tight sands gas and methane from geopressurized aquifers) and potential imports of liquefied natural gas (LNG) or pipeline gas from Mexico, Alaska, and Canada.

In OTA's opinion, the claim that the resource base is unimportant to "midterm" (1985-2000) supply is arguable. Most theories of resource depletion imply that the "easiest" part of the resource base—for gas, this would be the largest, most accessible fields—tends to be discovered and exploited in the early stages of development and that declines in discovery rates and production will occur well before the "last" resources are discovered and extracted. Consequently, the resource estimates of USGS and the even higher estimates of the Potential Gas Committee (PGC) do *not* necessarily imply a capability to continue gas production at current levels for decades to come. These estimates indicate that we have already produced about 40 percent of the Lower 48 gas resource obtainable within the current price technology regime. The remaining 60 percent will be more difficult and more expensive to find and eventually extract than the already produced portion. The very pessimistic recent estimates of M. King Hubbert[1] imply that the United States may have produced 70 percent of all the gas it shall *ever* produce in the Lower 48. The Hubbert estimate thus implies that the United States may encounter an almost immediate dropoff in discoveries and reserve additions, followed shortly thereafter by sharp reductions in gas production. Even the more optimistic USGS and PGC estimates do not deny the possibility of significant reductions in supply within this century.* Therefore, an understanding of resource base estimates is important to midterm as well as long-term planning regarding natural gas policy.

In this section, OTA has not attempted to create a new, independent assessment of U.S. natural gas resources nor to settle on any existing assessment as the "best." Instead we attempted to accomplish the following four goals:

1. To give the reader an idea of how natural gas resource assessments are made.
2. To describe the problems associated with general resource assessment methods and with particular individual assessments.
3. To define the continuing areas of controversy about the size and characteristics of the remaining gas resource base.
4. To convey OTA's evaluation of these controversies and of the credibility of some of the most widely used assessments.

RESOURCE BASE CONCEPTS

An important source of difficulty in interpreting and comparing resource base estimates is the failure of the estimator to state and explain precisely the boundaries of his estimate—his definition of the resource base—and the failure of the client to comprehend what a resource base is, or what *a particular* resource base is.

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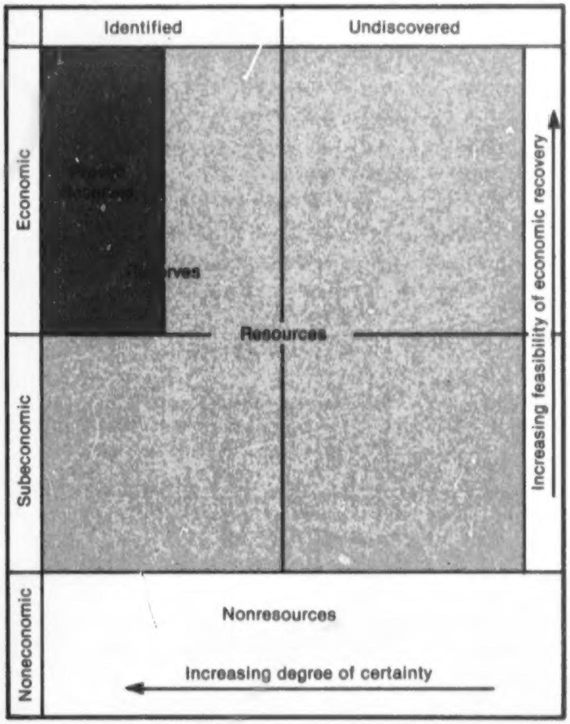
[1] M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," in *Oil and Gas Supply Modeling*, S. I. Gass (ed.), National Bureau of Standards Special Publication 631, May 1982.

*For a discussion about the production implications of the Hubbert, USGS, and PGC assessments, see ch. 5, "Approach Number 4—Graphing the Complete Production Cycle."

The well-known McKelvey Box (named after its originator, the former director of USGS) is a useful tool in explaining basic resource base concepts (see fig. 8). The McKelvey Box classifies resources according to their economic feasibility of recovery and the geologic certainty of their occurrence. The outer boundaries of the box define the total amount of the material—in this case, natural gas—remaining within the crust of the Earth. The top third of the box (the proportions are NOT meant to be indicative of magnitude) represents gas that is economically producible at current prices using existing technology. The middle third represents gas that is expected at some *future* time to be producible but is currently not economically producible, either because of the absence of recovery technology or because of economic conditions. The lower third represents gas accumulations under such difficult physical conditions that they are likely never to be economically producible. Obviously, our inability to accurately project future economic conditions and future technology developments prevents us from knowing where to place the line between subeconomic resources and "nonresources."

Figure 8.—The McKelvey Box



SOURCE: Adapted from V. E. McKelvey, "Mineral Resource Estimates and Public Policy," *American Scientist*, vol. 60, No. 1, 1972, pp. 32-40.

The left half of the box represents identified resources—"resources whose location and quantity are known or are estimated from specific geologic evidence."[2] The economically recoverable portion of the identified resources is called "reserves" in the box, but this is not a universally accepted definition. (However, it is generally accepted that use of the term "reserves" to designate the total recoverable resource is a poor usage of the term. Reserves should always refer to gas that is in some sense within the ready inventory available for production.) *Proved or measured reserves* are the most certain portion of the recoverable identified resource, gas which has been estimated from geologic evidence *supported directly by engineering measurements.* An actual physical discovery by drilling is necessary for inclusion within this category. The remainder of the recoverable identified resource is somewhat poorly defined because of disagreement about what "identified" or "discovered" means. To USGS, for example, untapped reservoirs in discovered fields belong to the "discovered" resource,[3] whereas to the PGC, they are "undiscovered."[4]

A critical feature of the components of the resource base is that they are not static. As the production and discovery process continues, gas flows out of reserves and is processed, distributed, and consumed, and other gas moves from "undiscovered" to "identified" as geologic knowledge increases. Additionally, improved technology and economics cause gas to move from the subeconomic to the economic portion of the resource base. For example, improvements in offshore drilling technology may allow drilling in deeper waters and more hostile conditions, opening up new territories to development. Higher gas prices may allow the development of smaller reservoirs that were previously uneconomic, or allow known economic reservoirs to be developed more intensively and drained to lower abandonment pressures.

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[2] G. L. Dolton, et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States,* U.S. Geological Survey Circular 860, 1981.

[3] Ibid.

[4] Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of December 31, 1980),* May 1981.

In the history of development of nonrenewable resources, the process of advancing technology and knowledge and of changing economic conditions has not always been smooth. Consequently, assessments of nonrenewable resources have tended to run in cycles. The discovery of resources in areas or under geologic conditions where they had not been expected or the development of new extraction and processing technologies can generate higher estimates of the remaining resource which may then taper off as that portion of the resource base is systematically depleted. For most resources, analysts assessing the remaining recoverable materials at the end of each cycle have been convinced that the most recent cycle upturn was the last and that resource depletion was imminent. They have been proven wrong time and again.*

Recognizing this, many resource estimators have confined their assessments to only a portion of the McKelvey Box, usually the top third and a small portion of the middle, subeconomic third. In doing so, they explicitly accept the possibility that changing economic and technological conditions could make their recoverable resource estimates obsolete. Unfortunately, the stated boundaries of the assessments are seldom very precise, and it is not always clear that the estimators have consistently followed their own specified rules for including and excluding portions of the total physical resource. Furthermore, besides the ambiguity of the boundary definitions, some resource assessments have chosen different boundaries than the "top third and a small portion" indicated above. Hubbert, for example, claims to capture the *ultimately recoverable resource*—the top two-thirds of the box—in his estimate, although he restricts the estimate to "conventional" gas and excludes such sources as methane in coal seams.[5]

The differences in economic/technological boundary conditions between alternative gas resource assessments is one of several reasons why comparisons of assessments must be handled with caution. Table 5 lists some of the common problems encountered in comparing estimates.

Table 5.—Why It Is Difficult to Compare Resource Estimates

- Geographical areas (or geological limitations, such as depth) included in the estimate may be different—especially offshore boundaries.
- Assumptions about economic conditions and the state of technology may be different. Also, these assumptions are often poorly defined and appear in some cases to have been applied inconsistently.
- Some estimates may have included some unconventional resources.
- Areas that are currently legally inaccessible (e.g., wilderness areas) may or may not be included.
- Definitions of "undiscovered" may differ; they may or may not include undiscovered reservoirs in known fields.
- Degree of optimism about estimates (e.g., assigned probabilities) may differ.
- Estimates may or may not correct for liquid content and for impurities.

SOURCE: Office of Technology Assessment, 1983.

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*Oil has undergone such cycles of apparent depletion followed by large new discoveries and drastic upward revisions in resource estimates. Two other well-known materials that have undergone similar cycles are uranium and iron ore.

[5] Hubbert, op. cit.

APPROACHES TO GAS RESOURCE ESTIMATION*

Although the extensive literature on oil and gas resource assessment identifies a wide variety of estimation techniques, all of the techniques fall into two basic categories. *Geologic approaches* rely on information and assumptions about the physical nature of the resource: volumes of sedimentary rock, numbers of geologic structures, presence of "source" rocks, time profiles of subsurface pressure and temperature, and the like. *Historical approaches* rely on the evaluation and extrapolation of past trends in gas production and discovery in the assumption that the size and character of the resource base, rather than transitory economic conditions and technological developments, are the most important factors controlling the discovery and production cycle. If this assumption is correct, the evidence provided by the manner in which the development cycle has unfolded can be used to ascertain the nature of the resource base.

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*This section is based largely on U.S. Geological Survey Circular 860, "Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States," G. L. Dolton, et al., 1981; and D. A. White and H. M. Gehman, "Methods of Estimating Oil and Gas Resources," AAPG Bulletin, vol. 63, No. 12, December 1979.

Geologic Approaches

Geologic approaches run the gamut from simple—for example, the collection of expert geologic opinion on the size of the overall resource base—to complex procedures involving probabilistic estimates of the geochemical and geologic factors affecting the formation, migration, and accumulation of gas. The methods listed may be used in combination.

In *geologic analogy*, untested areas are examined for comparison with known producing areas. Comparisons range from simple evaluations of hydrocarbon source beds or reservoir beds to evaluation of dozens of factors. Because the use of analogy is basic to all geologic and geochemical understanding, this method in some sense is the basis for all the other methods.

In the *Delphi approach,* in its simplest form, each member of a group of geologists evaluates the geologic evidence available for an area and estimates the area's potential resources. These individual estimates are then reviewed by the group, possibly modified, and then averaged into a single estimate. This approach may also be used as a tool to assist other resource estimation approaches, as when experts are asked to jointly evaluate the hydrocarbon yield of an untested area in barrels per acre-foot as an input to a resource assessment using a volumetric yield approach (see below).

Areal-yield and volumetric-yield approaches involve the estimation of the amounts of hydrocarbon per unit area or volume of potentially productive rock in a region and the multiplication of these estimated yields by the appropriate area or volume. The yields are generally calculated by geologic analogy.

Geochemical material balances, elaborations of the *volumetric-yield approach,* attempt to account explicitly for the process of gas generation, migration, and entrapment. Rather than estimating a simple volumetric yield, for example, this approach might estimate the amount of organic matter in source beds, the fraction converted into hydrocarbons, the fraction actually able to move from the source beds into reservoirs, and finally the fraction of this amount actually trapped and concentrated and thus available for extraction.

Field number and size approaches attempt to count or estimate the number of prospective fields in the area being evaluated and to estimate their success rate and size distribution in order to yield an overall area resource estimate. Estimation methods include actual counting of structural traps by using seismic surveys, extrapolation from historic field size distributions (a historic approach, as discussed below), and calculation of success ratios by geologic analogy. Other levels of aggregation besides the field are also used; *play analyses,* for example, focus on groups of fields or prospects with several common geologic characteristics.

Some generalizations can be made about these approaches. The simple methods that use few factors to calculate gas resources all share the risk that key geologic factors, such as the temperature history of the rocks, may be left out. The converse is that the more complex methods, such as geochemical material balances, may assume a higher level of geologic knowledge than currently exists. Although the breakdown of the resource assessment into several individual components appears precise, the uncertainty associated with each component is quite large and the potential for error in the resource estimate is high. For example, incorporating factors such as pressure and temperature histories into resource estimation allows the estimator to account directly for the probability that petroleum actually was formed and survived. However, because the geology of most areas has changed significantly over time, it is difficult to trace these changes to reconstruct the temperature and pressures that existed during the periods of hydrocarbon formation, migration, and accumulation.

The simpler methods are most useful in the early stages of development of a basin when few data are available and the need for expert judgment and intuition is at a peak. The obvious disadvantage, however, is that documentation of the estimation process is minimal or, in the case of the simplest Delphi approach, lacking entirely. The credibility of these estimates, then, rests mainly on the reputation of the experts involved in the assessment or of the sponsoring organization.

Finally, the geographically disaggregated approaches, such as play analysis, are most useful when considerable exploration data are available. Many analysts think highly of these approaches, perhaps because the approaches deal in units that most accurately reflect the discovery process and thus allow participants in the resource assessment to draw most readily on their experience for geological analogs.

Historical Approaches

A variety of historical approaches to resource estimation rely on extrapolation of historical trends in production, reserve additions, and discovery rates as functions of time, number of wells drilled, or cumulative feet of exploratory drilling. Some of these approaches lack explicit assumptions about geology and simply search for curves that achieve the best fit to the data. Others (e.g., some of Hubbert's approaches) first assume general models of the production and discovery process and then adjust the models to fit the data.

A variety of formulations can lead to an estimate of the resource base. One simple example is shown in figure 9, which plots the rate of discovery of natural gas, in thousands of cubic feet per foot of exploratory well drilled, versus the cumulative footage drilled. An exponential or other function can be fit to the historical data and extrapolated into the future. After *f* feet have been drilled, the area under the curve is equal to the total amount of gas discovered up to that point.* The total resource base can then be estimated by measuring the area under the curve when it has been extrapolated to the point where all recoverable gas has been located. This point is assumed to be:

- when the amount of gas discovered per foot of drilling falls below some chosen lower limit, or
- when the cumulative exploratory footage is judged high enough to have allowed essentially all prospective acreage in the United States to have been explored.

Although Hubbert's estimate of gas resources will be reviewed individually later, historical approaches to gas resource estimation *as a class* have some common limitations. First, areas that are not "mature"—that do not have a substantial drilling or discovery history—are not represented in the historical data base and can be included in the assessment only if one is willing to assume they are part of the development process of a larger area and are not really independent. Consequently, Alaska is typically not included in the historical approaches, and the offshore areas are sometimes excluded as well. This limitation can be a problem with geologic as well as geographic categories; there is some question, for example, as to whether deep gas (below 15,000 ft) should be included in a "historical" resource estimate.

Second, since the resource estimates are totally dependent on extrapolations of the historical record, they depend heavily on the accuracy of this record. In the case of natural gas, this accuracy is probably poor. Through much of its discovery and production history, gas was usually a byproduct of the search for and production of oil and in the early years was often considered to be of very low value at best. Much gas was flared or otherwise wasted, production records were not kept, and gas discoveries often went unreported.

Third, all of these methods share the common assumption of all trend extrapolations: the future will be a reflection of the past. However, the "past" in the case of gas exploration and development has had interludes of radical change in the economic underpinnings and Government regulation of the industry and, to a certain extent, in the technology and geologic understanding driving the development process. Consequently, the historical approaches contain the implicit assump-

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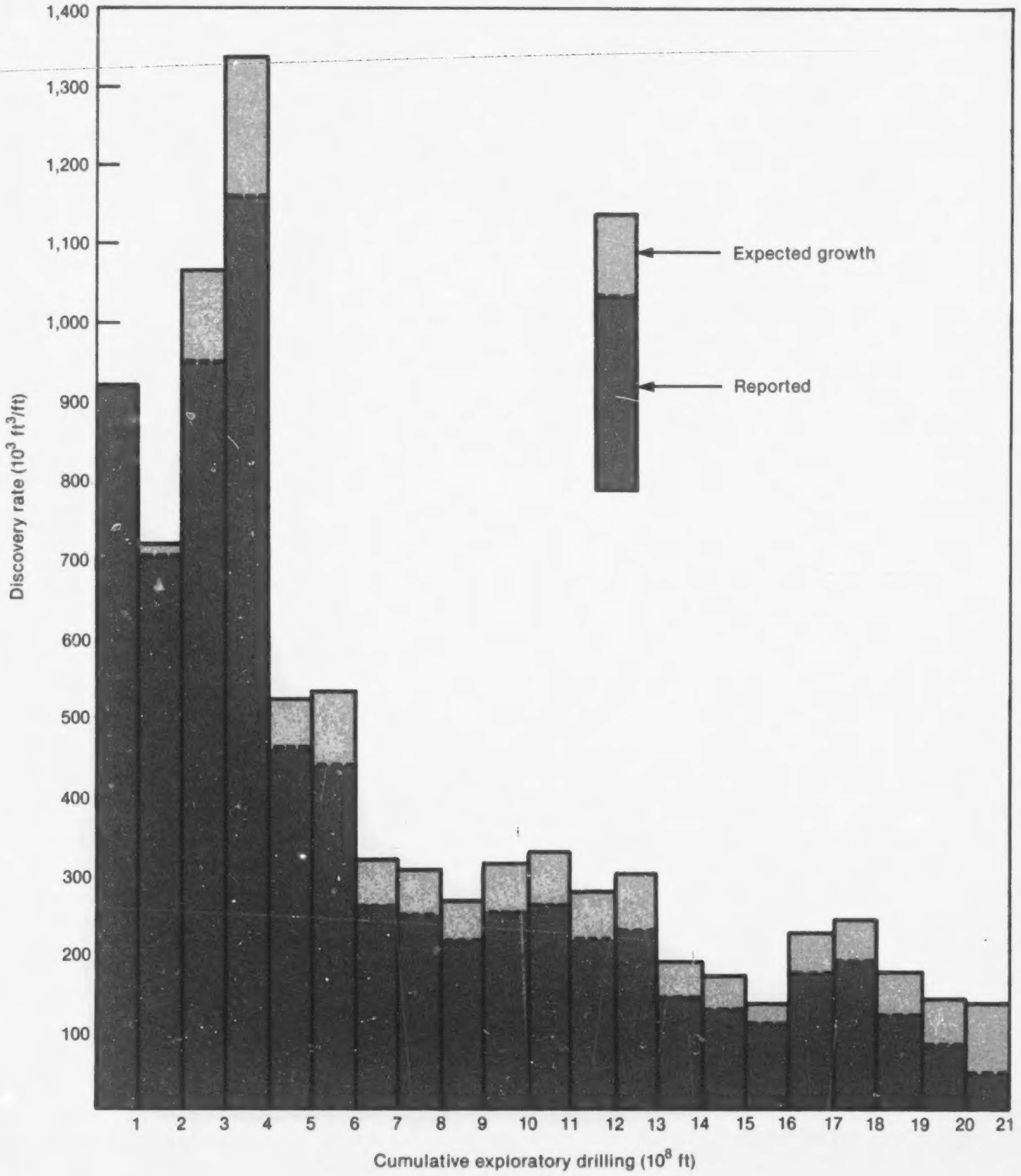
*Area=$\int_0^f$ (amount of gas discovered per foot drilled) d (cumulative feet drilled).

Figure 9.—Discoveries of Recoverable Natural Gas in the Lower 48 States v. Cumulative Exploratory Drilling



SOURCE: David H. Root, USGS.

tion either that the process of change will continue in the same manner in the future or that the physical nature of the resource base—unchanging except for changes wrought by development itself—is the main force driving gas development. In the long run, the physical nature of the resource base is seen as overwhelming the importance of volatile and transitory events or forces such as Government regulations and gas demand and price in determining the shape of the development curves.*

Fourth, it is difficult to define the economic, technologic, geographic, and geologic boundaries of a resource assessment based on historical trends. For example, data on the development of U.S. gas resources tracks a steady expansion of geographic coverage of exploration and production, an increase over time in the depth of wells, and a radical improvement in exploration technology. Did historical assessments of the U.S. gas resource done *before* Anadarko deep drilling include or exclude this deep resource? Will an assessment based on historical data account for a new Overthrust Belt type of development? To the extent that the historical curves capture past change, can they account for future changes? These questions are essentially unresolved. A common criticism of historical approaches is that they do not adequately capture the effect of new technologies and other changes. However, there is little agreement on what they *do* capture: opinions range from the full capture of future economic conditions[6] to the capture only of gas that would be discovered and produced under the socioeconomic conditions of the last several decades[7]—in other words, from the top two-thirds of the McKelvey Box to only the top third.

It is worth noting that a substantial "surprise"—e.g., the unexpected discovery of a new geologic "horizon"—cannot be accurately predicted by a historical approach. This is because a true surprise will not have affected the previous discovery and production history in any discernible manner. Therefore, the historical method will yield the same resource estimate *no matter how big the surprise turns out to be*. (Although the geologic approach cannot predict such a surprise, it can incorporate its effects immediately for future predictions.)

Fifth, although "historical approaches" seek to extrapolate trends that are functions primarily of the resource base and are relatively unaffected by transient economic effects, the available data may be too aggregated to allow this. Generally, the data measure processes that are made up of two or more components, some of which *are* sensitive to market conditions. For example, the finding rate of new field wildcats may be used to represent the success of the discovery process.* However, finding rate data measure the combined success of at least two quite different kinds of exploration. The high-risk, high-payoff wildcats represent the search for large fields in untried areas and the exploration of older areas based on new geologic interpretations. The finding rate of these wildcats is a critical determinant of the long-term replenishment of proved reserves. The low-risk, low-payoff wildcats represent the redrilling of old, formerly uneconomic areas, or the clustering of exploratory drilling around a successful new strike. Because drilling statistics do not separate new field wildcats into different risk categories, the data on low-risk, low-payoff drilling, which is very sensitive to market conditions, dilutes and distorts the data on the drilling activity most relevant to ensuring the future of gas production.

The problem of using a single data series to measure a process that has two or more dissimilar components becomes more acute as larger and larger aggregations, geographical and otherwise, are used. Compiling the data for individual provinces may be useful because, for example, exploratory drilling on a local scale is more likely to be either high or low risk rather than a combination of the two. Thus, a disaggregated approach conceivably may be more successful than a national one in appropriately interpreting implications of a changing finding rate. On the other hand, the reduction in data points may tend to cause data series for small areas to be very erratic, and aggregation over larger areas may be necessary to detect long-term trends.

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*In support of this view, it is worth mentioning that neither the major technical advances in exploration nor the opening of new territories since World War II were of sufficient importance to restore the oil or gas discovery rate to pre-war levels; instead, the discovery rate continued a fairly steady downward drift for several decades, in seeming disregard of changing conditions and technology.

[6] Ibid.

[7] R. P. Sheldon, "Estimates of Undiscovered Petroleum Resources—A Perspective," U.S. Geological Survey Annual Report, Fiscal Year 1978.

*Discovery data generally is preferred over production data in a historical approach because the discovery cycle is always a few years older than the production cycle. Extrapolation to the end of the cycle consequently is less severe for discovery than for production.

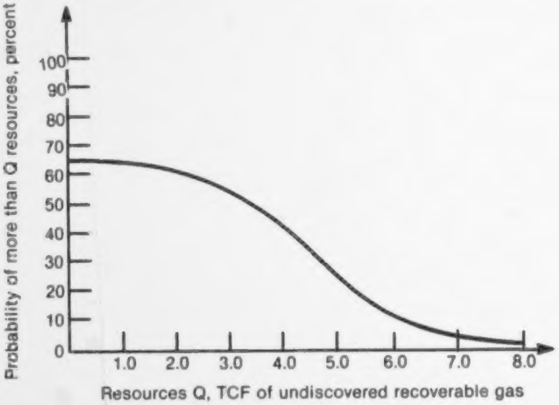
Dealing With Uncertainty

It must seem obvious from past mistakes that petroleum resource assessment is a risky business. For example, tracts in the offshore South Atlantic shelf were recently leased to industry for millions of dollars (proceeds from the first two sales, lease sales 43 and 56, exceeded $400 million[8]) with an industry/Government consensus that large volumes of economically recoverable oil and gas were present, yet drilling results have thus far been negative.[9] Similarly, expected large fields in the Gulf of Alaska have failed to materialize under the drill. Conversely, drilling since 1975 in the Western Overthrust Belt has revealed a large, previously misunderstood potential for oil and gas. Even the calculation of proved reserves is uncertain and in some instances (e.g., Louisiana and Texas) has required extensive corrections in later years.

A major reason for the risk in resource assessment is that the presence of economically recoverable concentrations of petroleum requires the completion of an unbroken chain of events, each of which is difficult to predict. First, adequate amounts of source rock containing organic material must be present. Second, the temperature and pressure conditions must remain within a range capable of transforming the organic matter into petroleum. Third, geologic conditions must be right to allow the petroleum, once generated, to migrate. Fourth, permeable and porous rocks must be in the migration path to serve as a reservoir. Fifth, a geologic structure must be present to trap the petroleum so it can accumulate into commercial quantities. Not only the *availability* of the required conditions but also their *timing* are critical. The presence of an adequate trap, detectable with seismic or other search techniques, does not guarantee that the trap was present at the time of petroleum migration; if it was not, or if the trap was breached at some time after the petroleum entered the reservoir, the oil or gas would have escaped and would probably have reached the surface and dissipated.

Some estimators either (apparently) ignore uncertainty or acknowledge it only by expressing their results as an undefined or vaguely defined range (e.g., "optimistic/pessimistic"). Uncertainty *can* be dealt with explicitly and quantitatively in resource estimations, however. Resource estimates, or the individual factors used in estimating resources (e.g., volume of sedimentary rock, hydrocarbon yield factor), can be expressed as probability functions instead of point estimates or ranges. For example, figure 10 illustrates a hypothetical probability function for the undiscovered recoverable gas resources of a single province. The curve shows the probability that there are more than Q undiscovered resources in the province.* "Probabilistic estimates" such as these cannot be directly added (or, in the case of estimates for volumes and yield factors, multiplied) to form ag-

Figure 10.—Probability Distribution for Undiscovered Recoverable Gas Resources in a Province



NOTE: "More than" cumulative distribution function.

SOURCE: David H. Root, USGS.

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[8] USGS Open-File Report 82-15, South Atlantic Summary Report 2, May 1982.

[9] Ibid.

*The probability is not 100 percent at $Q = 0$ because there is a finite probability that the province does *not* have "more than 0 resources;" in a totally unexplored province, this probability of zero recoverable resources may be quite large.

gregate resource estimates, such as an estimate of total U.S. gas resources. Instead, they are added statistically; one commonly used technique is called Monte Carlo simulation (see box A).*

Although probabilistic methods are useful for displaying some of the uncertainties associated with resource estimation, the language used to describe the results of these methods is often misunderstood by a lay audience. It is critical to remember that the accuracy of probabilistic estimates is limited by the extent to which the estimators' model of the physical universe is a correct one. In estimates such as those of USGS, the "95th percentile" estimate should *not* be interpreted as meaning that there actually is a 95 percent probability that the resource base is larger than this estimate. It should *instead* be interpreted to mean only that the assessors, *with whatever limitations their geologic "mindsets" and their limited data may impose on them,* believe that there is such a 95 percent probability. This difference may seem subtle, and it certainly is not kept secret by the estimators, but it is nevertheless important.

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*In Monte Carlo simulation, a value is selected at random from each of the separate probability functions that are the components of the resource estimate (e.g., for a nationwide assessment, the components are the individual province assessments; for a volumetric resource assessment, the components are the volume of sedimentary rock and the hydrocarbon yield factor). These values are then combined arithmetically to form a single point estimate of the resource base (for the nationwide assessment, the values from each province are added; for the volumetric, the values selected for volume and yield are multiplied). This procedure is repeated many times, each time producing a new point estimate, until a probability function for the resource base is formed.

Box A.—Does the Monte Carlo Technique Underestimate Uncertainty?

An analytical problem with the probabilistic estimates of national gas resources is that the Monte Carlo method, when used to link individual province estimates together, usually assumes that the individual estimates are completely independent from one another. In lay language, "independence" of this sort means that any additional information gathered from one petroleum province can in no way be applied to any other province, and that a change in one province's estimate won't affect any others' estimates. In other words, independence assumes that so much is known about the geologic principles underlying petroleum formation and occurrence that the only things to be learned by additional drilling are site- or province-specific.

In reality, few if any geologists would claim such an advanced state of knowledge. Instead, it seems likely that additional knowledge of a pessimistic nature—discovery that resources in several provinces actually were leaning toward the low end of the original estimate—can cause estimates in some other provinces to be revised downwards, and vice versa. For example, geologists are currently uncertain about the number of small fields* in the resource base because past exploration ignored the discovery of such fields (they were too small to be considered producible). If the search for such fields became highly successful in one or more provinces, this success would probably cause geologists to reassess the significance of small fields in other provinces as well. Province-to-province dependence of this sort implies that the "optimistic" (high) national resource estimates probably aren't optimistic enough, nor are the "pessimistic" estimates pessimistic enough. In conclusion, the high-low ranges flowing from Monte Carlo-based probabilistic resource calculations that assume province-to-province independence are too narrow, that is, they understate the uncertainty associated with combining the individual province estimates into a regional or national estimate. The error introduced by the actual dependence of the estimates may be reduced, however, by careful choice of province boundaries and by making the provinces large enough.

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*A small field may be defined as one with an ultimate production of less than 10 million barrels of oil, 60 billion cubic feet of natural gas, or comparable amounts of oil and gas energy expressed as barrels of oil equivalent (BOE), using 6,000 cubic feet of gas as equal to 1 barrel of oil.

COMPARISON AND REVIEW OF INDIVIDUAL ESTIMATES

Although many readers may be aware only of the work of USGS and perhaps that of M. King Hubbert, assessments of the U.S. natural gas resource base are quite numerous and use a wide variety of approaches. Table 6 lists some of the more recent estimates of the "ultimately recoverable resource"—the total amount of gas that will be produced. The table also shows estimates of the recoverable resource remaining as well as the resources not yet added to proved reserves. The wide range of mean estimates for the remaining resources in the Lower 48 States—244 to 916 trillion cubic feet (TCF)—implies, in turn, a wide range in the outlook for future gas production, especially in the longer term.

Many available resource assessments are poorly documented and cannot be evaluated. OTA has reiewed some of the more widely known estimates, however, including those of USGS, PGC, the RAND Corp., and M. King Hubbert.

U.S. Geological Survey

Recent estimates of undiscovered gas resources by USGS, as presented in 1975 in "Circular 725"[10] and more recently in 1981 in "Circular 860,"[11] are

Table 6.—Alternative Estimates of Ultimately Recoverable and Remaining Natural Gas in the United States (TCF)

Estimator	Publication date	Ultimately recoverable resources: Lower 48	Ultimately recoverable resources: Total U.S.	Remaining resources Lower 48, 1983[a]	Remaining resources not yet added to proved reserves, Lower 48, 1983[b]
Mobil	1974	—	1,076-1,241-1,456	—	—
Garrett	1975	—	1,313	—	—
Wiorkowsky	1975	1,221-1,289-1,357[a]	—	595-663-731	421-489-557
Bromberg/Hartigan	1975	966[c]	—	340	166
Exxon Attainable	1976	—	917-1,112-1,577	—	—
Shell	1977	946	910-1,075-1,260	320	146
IGT	1980	—	1,288-1,798	—	—
PGC	1983	1,542	1,711	916	742
Hubbert (1)	1980	870	—	244	70
Hubbert (2)	1980	989[d]	—	363	189
RAND	1981	902	989	283	109
USGS	1981	1,400	1,422-1,541-1,686	774	600

[a] Approximate cumulative Lower 48 production through 1982 was 631 TCF, of which about 5 TCF is in underground storage. "Remaining resource" is "Lower 48" (ultimately recoverable) column value minus 631 TCF plus 5 TCF.

[b] Lower 48 proved reserves assumed to be 169 TCF at 12/31/82 (excluding underground storage).

[c] Original estimate for onshore gas only. Total arrived at by adding USGS (mean) estimate for ultimately recoverable offshore gas in Lower 48 (235 TCF).

[d] Based on an analysis of finding rates by David Root, USGS.

SOURCE: **Mobil**—J. D. Moody and R. E. Geiger, "Petroleum Resources; How Much Oil and Where," *Technology Review*, March/April 1975. Verbal comments by John Moody at a FPC presentation, Apr. 14, 1975.

Garrett—R. W. Garrett, "Average of Some Estimates by Major Oil Companies and Others, 1975," oral presentation at Executive Conference of the American Gas Association, June 9-11, 1975, cited in Potential Gas Committee, *A Comparison of Estimates of Ultimately Recoverable Quantities of Natural Gas in the United States*, Gas Resource Studies No. 1, Potential Gas Agency, April 1977.

Wiorkowski—J. J. Wiorkowski, *Estimation of Oil and Natural Gas Reserves Using Historical Data Series: A Critical Review*, unpublished manuscript, 1975, cited in J. J. Wiorkowski, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review," in *J. Am. Stat. Assoc.*, vol. 76, No. 875, September 1981.

Bromberg/Hartigan—L. Bromberg and J. A. Hartigan, *Report to the Federal Energy Administration*, unpublished manuscript, 1975, cited in Wiorkowski (1981), noted above.

Exxon—Exxon Co., U.S.A., Exploration Department, "U.S. Oil and Gas Potential," March 1976. *Oil and Gas Journal*, "Exxon Says U.S. Still Has Vast Potential," Mar. 22. 1976.

Shell—C. L. Blackburn, Shell Oil Co., "Long-Range Potential of Domestic Oil and Gas," presented at NAPIA/PIRA Fall Conference, Boca Raton, Fla., Oct. 19, 1978. *Oil and Gas Journal*, "Shell: Alaska Holds 58% of Future U.S. Oil Finds," Nov. 20, 1978.

IGT—J. D. Parent *A Survey of United States and Total World Production, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium*, Institute of Gas Technology, Chicago, August 1980, cited in American Gas Association, "Energy Analysis: A Comparison of U.S. and World Remaining Gas and Oil Resources," Aug. 7, 1981.

PGC—Potential Gas Agency, *News Release—February 26, 1983.*

Hubbert (1) (2)—M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," in *Oil and Gas Supply Modeling*, S. I. Gass (ed.), National Bureau of Standards Special Publication 631, May 1982.

RAND—R. Nehring with E. R. Van Driest II, *The Discovery of Significant Oil and Gas Fields in the United States*, R-2654/1-USGS/DOE, RAND Corp., January 1981.

USGS—G. L. Dolton, et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.

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[10] B. M. Miller, et al., *Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States,"* USGS Circular 725, 1975.

[11] Dolton, et al., op.cit.

probably the most widely used gas resource estimates. The most recent estimate uses a Delphi-type approach whereby teams of geologists arrive directly at resource estimates for individual petroleum provinces through a subjective assessment of the available geological data and the results of a variety of estimation approaches (including volumetric, play analysis, and other geologic methods as well as finding-rate analyses and other historical methods).

The estimates are probabilistic, that is, each is presented as a curve that shows the probability that the actual resource base is larger than any particular value (see fig. 10). Thus, the 95th percentile estimate reflects the USGS assessment that there is a 95 percent probability that the actual resource base is at least this large. Because only those resources that are virtually certain to exist are included, this estimate would be considered the pessimistic extreme of the range of estimates. The individual province estimates are added statistically, using a Monte Carlo technique, to achieve a national estimate. As described previously (box A), the "high-low" range described by the 5th and 95th percentiles is narrower than would be the case if the interdependence of individual province estimates could be taken into account. However, the potential problem was described as minor by the experts OTA talked with, largely because of USGS's selection of province boundaries.

The USGS assessment is unusual in that individual probabilistic estimates are available for each of 137 provinces, providing a very fine level of detail. Also, detailed information files on individual provinces are open to the public at USGS's Denver facility. As with most geologic estimates, the USGS estimate is not meant to include all resources that may be recoverable at any time, but is instead limited to the resources that "will be recoverable under conditions represented by a continuation of price-cost relationships and technological trends that prevailed at the time of assessment (1980)."[12] Consequently, resources that are currently in fields that are too small, under too much water, under geologic conditions that are too difficult, or are otherwise not economically recoverable are not reflected in the current estimates but could be expected to enter the recoverable resource base in the future if gas prices rise and technology improves significantly.

In contrast to the approach for estimating resources in undiscovered fields, USGS calculated the remaining resources in undiscovered pools in known fields and expansion of the proved areas of known pools* by using a simple extrapolation from historical records of gas-field growth.[13] Field growth is a significant source of gas, and USGS calculated the resources in this category to be about 172 TCF, or over one-fifth of the remaining gas resources. Unfortunately, the USGS approach to assessing this source is problematical because the historical growth rates of known fields have tended to be extremely variable, and the characteristics of fields discovered recently, and calculated by this method to yield the most growth, are quite different from the fields that supplied the historical data. In OTA's opinion, there is a significant potential for error in this approach.

In USGS's 1975 resource estimate, the economic boundary of recoverable resources also proved to be a problem; a survey of the assessment team revealed considerable differences between their various interpretations of the meaning of the boundary definition.[14] Although OTA undertook no formal survey for the 1981 assessment, informal talks with analysts close to the assessment process lead OTA to believe this problem still exists. For example, several analysts believe that part of the offshore resource in the USGS assessment is far too expensive to be developed unless gas prices escalate substantially. If this is correct, these resources are subeconomic, according to USGS's definition, and should not be included in the estimate of recoverable resources.

Another potential problem area in the assessment is the boundary between "conventional" and "unconventional" resources. The USGS estimate is of "undiscovered recoverable *conventional* resources (our emphasis)" and excludes "gas in low permeability ('tight') reservoirs" and other so-called unconventional resources.[15] The precise meaning of the exclusion is unclear, however. In moving towards lower and lower permeabilities, there is no general consensus about where "conventional but low permeability reservoirs" end and "unconventional 'tight' reservoirs" begin, and USGS has not defined a threshold value of permeability to separate the two.

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[12] Ibid.

*These resources are called "inferred reserves" in the USGS assessment and are equivalent to the "Probable potential resources" in the PGC assessment.

[13] Ibid, app. F.

[14] Personal communication with John Schanz, Congressional Research Service.

Circular 860 does imply, however, that some undiscovered gas in low-permeability reservoirs was excluded from the estimated conventional resource base even though the gas could currently be defined as economically recoverable. Consequently, all else being equal, the USGS estimate should be expected to be smaller than estimates that include *all* economically recoverable gas resources.

It also is commonly believed that USGS's Delphi technique, described by USGS as relying on reviews of the results of a variety of approaches, relies primarily on the results of volumetric analysis. This reliance on the volumetric approach is probably due to data limitations. The USGS data base, although substantial, is generally limited to public data.[16] Volumetric analysis has often been associated with relatively optimistic resource assessments.

Potential Gas Committee

The estimates of "potential" gas resources—recoverable resources that have not been produced or proved—by the PGC represent the gas industry counterpoint to the USGS estimate.*

PGC's most recent estimate of the total U.S. potential resource—876 TCF for the end of 1982[17]—represents a decrease from the year-end 1980 estimate.[18] Because this decrease is balanced by additions to proved reserves during the period, the old and new estimates are similar in their estimates of total ultimately recoverable resources.

The PGC estimation procedure is generally structured like a volumetric analysis in that the PGC analysts separately estimate the volume of potential gas-bearing reservoir rock and a yield factor (amount of gas per volume of rock) and multiply the two to arrive at an initial resource estimate. The analysis combines aspects of other geologic approaches, however. It is also strengthened by the separate estimation of gas potential for 11 distinct geographical areas within the Lower 48 States, for three distinct categories of resource within the areas according to their state of development,* for offshore and onshore resources, for resources above and below a depth of 15,000 ft in the onshore portion, and for resources above and below water depths of 200 meters to a maximum of 1,000 meters offshore. The estimates "include only the natural gas resource which can be discovered and produced using current or foreseeable technology and under the condition that the price/cost ratio will be favorable."[19] These conditions are similar to those adopted by USGS, but what constitutes a "favorable price/cost ratio" remains unclear. The large proportion of deep resources incorporated in the estimate may imply, however, that PGC has included resources that will require prices above present market clearing levels.**

The PGC volumetric estimation procedure is considerably more sophisticated than early techniques that were based on total volumes of sedimentary rock. In the PGC analysis, the volumes of potential gas-bearing reservoir rock are estimated by adding up estimates of individual traps and trap sizes where sufficient data is available. According to PGC's methodology description,[20] techniques such as play analysis and field number and size approaches are used to construct an areawide volume estimate based on a variety of existing geological data. Yield factors (gas volumes/rock volumes) are then calculated by selecting appropriate analogs from producing areas and adjusting the yields to account for geochemical factors such as the thermal history of the source rocks. Finally, the analysts are asked to multiply the (volume) × (yield) estimates by their assessments of the probabilities that traps actually exist and that an actual accumulation of gas has occurred.

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[15] Dolton, et al., op. cit.

[16] G. Dolton, USGS, presentation at RAND workshop on estimating U.S. natural gas resources, Washington, D.C., Mar. 1-3, 1982.

*PGC is composed of members and observers from gas producers, pipelines, and distribution companies and observers from the American Gas Association, Department of Energy, Gas Research Institute, and other public and private organizations. The actual estimating workgroups consist mainly of industry employees and consultants, but State geological surveys are well represented, and some of the groups include personnel from Federal agencies and from universities.

[17] News Release, Potential Gas Agency, Feb. 26, 1983.

[18] Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of December 31, 1980)*, May 1981.

*The categories are "Probable," "Possible," and "Speculative" resources. Probable gas results from the growth of known fields, Possible gas is associated with the projection of plays or trends of a producing formation into a less well-explored area of the same geologic province, and Speculative gas is from formations or provinces that have not yet proven to be productive.

[19] Ibid.

**On the other hand, the actual price requirements for producing deep gas under free market conditions are uncertain, and it is possible that much of PGC's deep potential is producible at prices not far removed from today's.

The analysts also are asked to separately estimate "optimistic," "most likely," and "pessimistic" volumes of gas in a manner similar to that of the USGS. In contrast to USGS, however, PGC publishes only the "most likely" estimates. The other estimates are apparently used for review purposes only.

Because PGC publishes only the results of its analyses and does not release any internal details of the resource calculations (except for general methodology descriptions), and because it is essentially a gas industry organization, the credibility of PGC's resource estimates may be questioned. In OTA's opinion, however, the PGC estimates should be taken as a serious effort at resource assessment by analysts with excellent access to exploration data. The estimating workgroups, although composed mostly of industry employees, have a sufficient number of other participants—and a sufficient divergence of incentives within different segments of the industry—to prevent any attempts to subvert the assessment process significantly. Also, the long-term professional history of the organization (since 1966) and the oversight of the Colorado School of Mines are substantial arguments for accepting the PGC estimates as honest reflections of the professional judgment of the organization.

An advantage of the PGC estimates is that the basic methodology has been applied, with evolutionary changes, for 16 years. Table 7 shows the eight estimates of ultimately recoverable gas resources in the Lower 48 States produced by PGC since 1966. The consistency of these estimates is high. In fact, given the advances in technology and the major additions to the known boundaries of conventional gas supply that have occurred in the past 16 years,* the mildness of the upward trend in the estimates over this time period implies a movement toward more conservative estimates. This conservatism is particularly interesting in light of PGC's resource estimates being among the most optimistic of the major assessments.

In its 1982 assessment, PGC attempted to isolate that portion of the estimated potential resource that occurs in tight formations—tight sands with permeability levels less than 0.1 millidarcy (conforming to the Federal Energy Regulatory Commission definition for gas eligible for incentive pricing) and Devonian shales. A series of areawide estimates were produced for depths above and below 15,000 ft. The "tight" portion of the U.S. potential gas resource was estimated to be about 20 percent of the total, or 172 TCF.

This estimate is highly significant for two reasons. First, it demonstrates graphically the

Table 7.—Comparison of Potential Gas Committee Estimates of Ultimately Recoverable Gas Resources in the Lower 48 States

Estimate as of yearend	Ultimately recoverable resources (in TCF)
1966	1,283
1968	1,426
1970	1,498
1972	1,446
1976	1,396-1,421-1,446
1978	1,550
1980	1,502
1982	1,542[a]

[a] Approximate—A portion of the difference between the 1980 and 1982 estimates is due to discrepancies between the proved reserve values computed by AGA (used for the 1980 calculation) and the EIA (used for the 1982 calculation).

SOURCE: Potential Gas Agency, *Potential Supply of Natural Gas in the United States (as of December 31, 1980)*, May 1981; and Potential Gas Agency, News Release, Feb. 26, 1983.

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[20] Ibid.

*For example, the addition of the Western Overthrust Belt due largely to advances in seismic technology, and the addition of large amounts of gas from low-permeable formations due to advances in fracturing.

long-term growth in the "ultimately recoverable" gas resource base and offers some support to the optimistic view that advancing technology can overcome at least some of the effects of resource depletion. Second, to the extent that other resource assessors may have excluded tight gas from their estimates, it may bring the PGC estimate closer to the "mean" of gas resource estimates in table 6. Unfortunately, the definitions of the boundary conditions of most of the assessments in table 6 are not sufficiently clear to ascertain whether tight gas *that is recoverable under the PGC boundary conditions* were excluded or included. A possible exception, however, is the USGS assessment, whose stated boundary conditions appear to be more restrictive than PGC's. It is probable that some of the tight gas included in the PGC estimate was not included in the USGS estimate.

RAND/Nehring

Richard Nehring of the RAND Corp. has produced an assessment of conventional U.S. oil and gas resources by a method that stresses an evaluation of the discovery of significant fields.[21] The assessment incorporates a variety of approaches:

1. To estimate the growth of reserves in known fields, a combination of methods were used, including extrapolating by historical field-growth factors and by more analytical approaches that used available geologic information and known production practices.
2. To estimate the amount of resource remaining to be discovered in known producing plays, an approach based on extrapolating historical trends was used. The key to this approach was the establishment of a data base containing production and reserve values, the year of discovery, discovery method, trap type, depth, and other data for virtually every petroleum field discovered in the United States by 1975 larger than class C (10 million to 25 million barrels-of-oil-equivalent). Despite the emphasis on the historical record, however, the approach also incorporates geologic methods based on play analysis.
3. Play analysis was used to estimate the resources in new plays in mature regions.
4. Depending on the availability of data, a variety of approaches were used to estimate resources in the frontier (ranging from volumetric analysis to field number and size approaches).

The estimates for new plays in mature regions and frontier areas were "risked" (i.e., the probability that there are no recoverable resources in the play is taken into account), and the assessments of undiscovered resources were expressed as probability distributions in a manner essentially identical to that used by USGS.

The RAND assessment has been criticized because of its alleged failure to define the process by which its massive data base is translated into resource base conclusions. In OTA's opinion, the description of the methodology that appears in the RAND report is indeed brief and generalized and gives no specific examples of the assessment process. However, this failure is endemic to resource assessments as a class. Even the PGC assessment, which describes its analytical process in some detail, publishes no backup data and provides only the sketchiest details of the geologic reasoning behind its regional results. In contrast, the RAND assessment explicitly defines the historical and geologic reasons for its regional assessments and identifies—and argues against—opposing views. This approach allows at least a partial evaluation of the assessment, whereas most assessments can be evaluated only to the extent of either accepting or rejecting the final estimates.

At the core of Nehring's argument for his quite pessimistic estimate is the thesis that the geologic possibilities for finding substantial new oil and gas resources in the United States have been largely exhausted. Nehring identifies four major hypotheses about where significant amounts of oil and gas may yet be found—in fields below 15,000 ft in depth (for natural gas only); in subtle, difficult-to-detect stratigraphic traps; in small fields; and in frontier areas, including the Eastern and Western Overthrust Belts—and argues against high optimism in each, with the possible exception of the frontier areas. The four hypotheses and Nehring's countering arguments are summarized in box B. A more detailed discussion of these hypotheses is presented later in this chapter.

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[21] R. Nehring with E. R. Van Driest II, *The Discovery of Significant Oil and Gas Fields in the United States,* RAND Corp. Report R-2654/1-USGS/DOE, January 1981.

A second facet to this argument is that this exhaustion of geologic possibilities is reflected in the recent (disappointing) history of exploratory drilling. Nehring argues that optimistic assessments simply do not bear up under the weight of the question, "Is it likely that we will find as many large fields as this assessment implies must be there?" For example, table 8 presents a proposed field size distribution that would yield an undiscovered petroleum (oil plus gas) resource equal to that predicted in the 1975 USGS (Circular 725) onshore assessment. This distribution would also be approximately equivalent to the more recent 1981 (Circular 860) USGS assessment, although the more recent assessment is slightly more optimistic. In the table, the proposed distribution is compared to actual field discovery statistics for 1971 through 1978. The last column shows how long it would take to find the necessary number of fields of each size category if the annual discovery rates of 1971 through 1978 continued for the life of the resource. In Nehring's opinion, the number of large fields that would have to be discovered to fulfill the USGS assessment is too large

Box B.—Rand Assessment's Arguments Against a Large Undiscovered Oil and Gas Resource Base

Deep Discoveries

- Major argument: Deep sediments are relatively unexplored. The few exploratory wells that have been drilled have been highly successful.
- RAND rebuttal: Physical and chemical conditions at these depths can be poor for methane stability. Reservoir porosity is often lacking. The area with deep sediments is a small fraction of total prospective sedimentary area. Most of the potentially productive structures in several basins have already been tested.

Stratigraphic Traps

- Major argument: Exploration has focused on structural traps, leaving significant opportunities in subtle stratigraphic traps.
- RAND rebuttal: Actually, considerable attention has been paid to stratigraphic traps in the Anadarko, Permian, and other basins. Aside from the stable interior provinces, multiple stratigraphic traps are unlikely. Because stratigraphically trapped reservoirs tend to be thin, large fields would cover large areas and would likely have been discovered. Large traps would be vulnerable to breaching and other causes of petroleum loss.

Very Small Fields

- Major argument: Because small gas fields were previously subeconomic, their discovery went unreported. Many more small fields exist than indicated by historical experience, and they form a sizable part of the recoverable gas resource.
- RAND rebuttal: Future reliance on small fields is based on assumption only; there is neither historical nor geologic argument to back it up. Also, because giant and large fields are two-to-four orders of magnitude larger than fields small enough to have been ignored in the past, there would have to be many tens of thousands of such fields to make any significant difference.

New Frontiers

- Major argument: Areas such as Alaska, the offshore Lower 48 States, and the Overthrust Belts have not been extensively explored and offer the potential for many significant discoveries.
- RAND rebuttal: Yes, but the small number of exploratory wells drilled in the Gulf of Alaska, the Outer Banks of California, the eastern Gulf of Mexico, the Southeast Georgia Embayment, and Baltimore Canyon are sufficient to severely dampen optimism for these areas. Some very promising areas do remain, however, including the deeper Gulf of Mexico, offshore Ventura Basin, and others.

SOURCE: Office of Technology Assessment, based on R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United States*, R-2654/1-USGS/DOE, RAND Corp., January 1981.

Table 8.—Field Discovery Implications of USGS Circular 725, Onshore Lower 48 Undiscovered Petroleum Resource

Field size[a]	Potential field size distribution: USGS Circular 725	Actual field discoveries		Implied time to find USGS undiscovered resource, constant annual discovery rate at 1971-78 average (years)
		1971-75	1976-78	
AAAA (>500/>3,000)	11	0	1	88
AAA (200-500/1,200-3,000)	44	0	0	Large but indeterminate
AA (100-200/600-1,200)	94	7	1	94
A (50-100/300-600)	199	7	3	159
B (25-50/150-300)	375	15	8	130
C (10-25/60-150)	977	44	22	118
D (1-10/6-60)	6,000	455[b]	—	66
E (<1/<6)	70,000	3,041[b]		115

[a] Values in parenthesis are size range in millions of barrels-of-oil-equivalent (mmboe)/billions of cubic feet of gas (BCF).
[b] 1972-76, Committee on Statistics of Drilling of the American Association of Petroleum Geologists.

SOURCE: Office of Technology Assessment, based on R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United States*, RAND Corp. report R-2654/1-USGS/DOE, January 1981. Also, personal communication, Richard Nehring.

to be credible. The long "times of discovery" in the table appear to reinforce this opinion. Unfortunately, none of the reviewed assessments defined a timeframe for complete discovery of the resource base, and an interpretation of the compatibility of a particular resource base/discovery rate combination is anything but straightforward. Also, the cessation of the American Gas Association's (AGA) reserve data (particularly reserve additions from new field wildcats) in 1979 prevents an easy check on whether post-1978 new field discoveries are ahead of discoveries during 1971-78; if they were, an argument could be made that the times in table 8 were misleadingly long because the assumed discovery rate was too low. On the other hand, the assumption in table 8 of a constant annual discovery rate for new gasfields over a 50- to 100-year period appears optimistic, even if the assumed rate is a bit low at the beginning of the period. This is because discovery rates *per foot drilled* appear likely to decline during this period, and a constant *annual* discovery rate thus implies an ever-increasing rate of new field wildcat drilling in an increasingly hostile *and expensive* environment.

One portion of the RAND assessment that now seems particularly suspect is the median estimate for field growth. The estimate (67 TCF) was only about one-third of the field growth estimates of USGS and PGC, a seemingly surprising difference considering the substantial amount of geologic knowledge available.* Recent large reserve additions from field growth make it clear that this estimate was too low.*

Hubbert

As noted earlier, M. King Hubbert is one of a considerable number of analysts who have used a historical approach—fitting curves to past trends in production, reserve growth, discoveries, etc.—to petroleum resource assessment. However, Hubbert's estimates must be accorded special attention. In 1962, Hubbert predicted that U.S. oil production would peak in 1969 and decline thereafter. He then held his ground in the face of substantial criticism until the peak actually did occur, only a year later than he said it would. From that time, his assessments of petroleum trends and resources have received considerably more attention and respect.

Hubbert's most recent estimate of the size of the natural gas resource base was made in 1980.[22] He estimates the ultimate cumulative production of conventional natural gas (Q_∞) for the Lower 48 States to be approximately 870 TCF. This is a remarkably low estimate given cumulative production to date of about 631 TCF and proved reserves of about 169 TCF;** if correct, it leaves only 70 TCF remaining to be added to reserves from the growth of known fields (calculated by

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*However, the recent controversy over the magnitude of additional gas that might be obtainable from old gas decontrol demonstrates that the availability of extensive geologic knowledge does not guarantee agreement over resources present.

*Nehring acknowledged this problem to OTA in a recent telephone conversation.

[22] Hubbert, op. cit.

**As of the beginning of 1983. Numbers are approximate because 1982 production and reserve data have not been published.

USGS to be 172 TCF) and new field discoveries. In other words, Hubbert's assessment implies that the precipitous declines of the early 1970's in Lower 48 proved reserves will resume again almost immediately, with subsequent drastic consequences for production rates within only a few years.

In his 1980 assessment, Hubbert obtained five separate estimates, using basically three approaches (table 9). In his first approach he derived equations for the magnitudes and rates of change of gas production and discoveries by noting some simple boundary conditions for the production cycle[*] and fitting a second order equation[**] to these conditions. By further manipulating the equation obtained by this exercise, Hubbert derived three separate but related methods of estimating Q_∞, two involving the curve of cumulative discoveries and one involving production rate as a function of cumulative production.

In his second approach Hubbert assumed that the ratio of the discoveries of natural gas to those of crude oil will tend to remain stable, allowing the gas resource base to be calculated as a simple function of the oil resource base.

The third approach involved extrapolating the declining finding rate for gas out to the point where exploratory drilling ceases and taking the area under the curve, as discussed in the earlier section on historical approaches to resource estimation (see fig. 8).

Table 9.—Hubbert's 1980 Estimates of Ultimately Recoverable Gas Resources in the Lower 48

Method of estimation	Q_∞ (TCF)
1. Extrapolating the plot of production rate as a function of cumulative production .	810
2. Estimating the approach of cumulative discoveries to Q_∞ as time approaches ∞ . .	871
3. Finding the equation of cumulative discoveries versus time	840
4. Using oil resource estimate and assuming stable gas/oil discovery ratio	876-896
5. Fitting and extrapolating the curve of discoveries per 10^8 feet of exploratory drilling	989

SOURCE: Office of Technology Assessment, based on M. K. Hubbert, "Techniques of Production as Applied to the Production of Oil and Gas," in *Oil and Gas Supply Modeling*, S. I. Gass (ed.), National Bureau of Standards Special Publication 631, May 1982.

Hubbert's work has been the subject of numerous critical appraisals.[23] This discussion will not attempt to review the appraisals but will incorporate some of their key points.

Of Hubbert's five estimates, the first three involve the assumption that the curves of *declining* production and proved reserves will be the mirror image of the curves of the (increasing) first portion of the resource development cycle. This derives from Hubbert's satisfaction with the "fit" of the simple quadratic equation he uses to approximate the curve of $\frac{\partial Q}{\partial t}$ v. Q. Aside from the criticism associated with all historical approaches—that the future does not have to look like the past, and more often than not doesn't—Hubbert never explores the possibility that he could achieve an equal or better fit with a different equation and thereby calculate a different Q_∞. Critics have shown, for example, that the resource base values obtained from fitting a curve to oil production data are sensitive to the type of curve used, and that Hubbert's assumed curve is not the best choice.[24] Although Hubbert's curve for oil *discovery* is more satisfactory, it may be that the less mature gas discovery curve is also flawed.[*]

The assumption of the fourth estimate, that the ratio of gas discoveries to oil discoveries will remain stable, appears to be very weak. The great majority (85 percent) of gas discoveries today are not associated with oil, and it is the consensus of many geologists that a large portion of the remaining gas resource lies below 15,000 ft in a physical environment hostile to the preservation of oil. A method predicated on stable gas/oil ratios would appear to guarantee an overly pessimistic gas resource base estimate.

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[*] Cumulative production Q is zero at the beginning of the cycle and Q_∞ at the end; the production rate $\frac{\partial Q}{\partial t}$ is zero when Q = 0 and also when $Q = Q_\infty$).

[**] $\frac{\partial Q}{\partial t} = C_1Q + C_2Q^2$

[23] For example, L. S. Mayer cites three: D. V. P. Harris, "Conventional Crude Oil Resources of the U.S.: Recent Estimates, Methods for Estimation and Policy Consideration," *Materials and Society* 1, 1977; N. Uri, "A Reexamination of the Estimation of Undiscovered Oil Resources in the U.S.," DOE/TM/ES/79-03, 1979, EIA; L. Mayer, et al., "Modeling the Rates of Domestic Crude Oil Discovery and Production," report to the EIA, Princeton University, Department of Statistics, 1979. (In comment on J. J. Wiorkowski, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review," *J. Am. Stat. Assoc.*, September 1981)

[24] E.g., J. J. Wiorkowski, 1981, "Estimating Volumes of Remaining Fossil Fuel Resources: A Critical Review," *J. Am. Stat. Assoc.*, September 1981, vol. 76, No. 875.

[*] The reasoning here is that the oil discovery curve gives more satisfactory results than the oil production curve because discovery is more advanced in its overall cycle. The less advanced, or less "mature," the curve, the less satisfactory will be the results.

In the last estimate, Hubbert fits an exponential curve to a historical plot of finding rate (the ultimate volume of gas to be produced from fields discovered by 10^8 ft of exploratory drilling) versus cumulative exploratory drilling, by requiring the curve to pass through the last data point and by requiring the area under the fitted curve to equal the area under the historical data plot (see fig. 8). This estimate has several serious problems. First the curve does not fit the data because it virtually ignores the "form" of the data and concentrates instead on the last data point.[25] Second, the estimate is very sensitive to this last data point, yet the magnitude of the point is the sum of a value (reported new field wildcat discoveries) that may vary with economic conditions* and with the state of depletion of the resource base plus a second value (reserve growth after the initial reporting period) that is, at best, a gross approximation.* Third, as with the first three estimates, Hubbert makes no attempt to explore the possibility that he could achieve a better "fit" with a different curve. His choice of a negative exponential curve is an assertion, made several times but unsupported by reasoning in his text.

An interesting observation about this last estimate is that despite the fact that the fitted curve is well under the trend line of the last several units of drilling—an ingredient for an overly *conservative* estimate—the estimate is considerably higher than the four other estimates in table 9.

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[25] Harris, 1977, op. cit.

*For example, a period of high-risk exploratory effort—responding to economic conditions that favor this sort of activity—will tend to yield high discovery rates, whereas one of lower risk effort responding to different conditions generally will yield lower rates. This is important here because Hubbert's analysis is dependent on the finding rate being a function only of the physical resource base and its state of depletion.

*The procedure used to estimate reserve growth utilizes the average growth rate over many years. However, the year-to-year historical growth rates have tended to be quite volatile, so the average growth rate for a single year or single period of 10^8 ft of drilling is at best a rough approximation. Furthermore, there are reasons to suspect that the *long-term trend* of reserve growth may now be turning downwards, causing a further error in an estimate assuming an unchanging trend.

RECONCILING THE DIFFERENT ESTIMATES

Which of these resource assessments are to be believed? In approaching this question, OTA used three criteria:

1. Is there a consensus, or even a "central tendency," in the scientific community?
2. How credible are the methods used by the assessors, in the abstract and in actual performance?
3. What do the different assessments imply in terms of geology and future discoveries? Are these implications credible?

Is There A Consensus?

In OTA's judgment, the range of opinion in the scientific community about the size of the natural gas resource is too wide to represent a significant consensus. Not only are there the obvious divisions along the lines of the various estimates, or simply between "optimistic" and "pessimistic," there is also an important division between scientists who believe in a particular estimate or range of estimates and those who do not believe that the state of knowledge is adequate enough to allow *any* reliable estimate to be made. Furthermore, some scientists believe that those estimates that invoke current technology and economic relationships—the great majority—are simply irrelevant, *whether or not they are correct within the constraints of these assumptions.* These scientists believe that both the inexorable advance of technology and rising prices that reflect resource scarcity will constantly push outwards the boundaries of the recoverable resource base. As noted previously, the history of resource estimation in general tends to support this view; cycles of predictions of scarcity followed by radical upward revisions in resource assessments appear to be common for nonrenewable resources (see box C). On the other hand, the USGS oil and gas resource estimates of the past decade and a half sustained some very substantial *downward* revisions as estimation procedures became more sophisticated.

Tables 10 and 11 summarize some of the key arguments used by the optimists and pessimists in explaining their positions on the probable size of the gas resource base. Because each of the arguments has merit, it is obvious that an unambiguous answer to the question, "How large is the U.S. gas resource base?" is not likely. Selection of a "best" estimate is further confused by the observation that some major disagreements exist even among assessors who appear to have the same general outlook (see box D), and some of the more important disagreements occur in areas where considerable geologic data exists to aid the resource assessments (and where, consequently, the *most* agreement might be expected).

Given what OTA would term a lack of consensus, is there at least a "central tendency?" What

Box C.—A Very Brief History of Petroleum Exploration

The history of petroleum exploration in general, and exploration for natural gas in particular, has been one of continuous movement toward new discovery horizons and resulting reappraisals of resource potential. The "movement" encompasses new geologic theories and "ideas," new exploration and production technologies, and new geographic areas.

During the first half-century of exploration following Drake's initial discovery in 1859, exploratory drilling was essentially random drilling, drilling at oil seeps, or drilling in areas where previous strikes had been made. Then a succession of geologic insights began to open up new horizons for exploration: first, the understanding that anticlines, some with surface manifestations, could serve as traps for petroleum; then, the discovery that petroleum deposits could exist in traps on the flanks of salt domes; next, the recognition of the petroleum potential of sand lenses and stratigraphic traps; and finally, the insight that petroleum could exist in recoverable quantities *underneath* thrusting plates, leading to the opening up of the Overthrust Belts to exploration and eventual large discoveries.

Another discovery "horizon" was the growing sophistication of the tools of the trade: the advent of the gravity meter and magnetometer, allowing the locating of geologic anomalies that might signal the existence of structural traps; the addition to the explorer's tool kit of refractive and then reflective seismology, which permitted the detailed mapping of geologic structures; the introduction of rotary drilling and advanced drill bits that allowed deeper horizons to be explored; the growing use of fracturing technologies, which opened up another geologic horizon in petroleum-bearing rock of low permeability; and the engineering triumphs of offshore drilling technologies.

At the same time, exploration and development moved into new regions, sometimes driven by the new technologies (e.g., the continental shelves) or new ideas (e.g., into Texas after realization of the importance of salt domes) and sometimes driven simply by the need for new supplies and dwindling prospects in the mature regions. Thus, exploration began in the Appalachian region but moved inexorably into Ohio and Kansas, into California and the Mid-Continent Region, to the onshore Gulf of Mexico, and spilled out into the Offshore, moved to the Overthrust Belt, and drove to deeper horizons in the Anadarko.

This history of constant movement to new horizons provides grist for the mill of both the resource optimists and the pessimists. The optimists focus on the seemingly continuous ability of explorationists to find new geologic concepts and to develop new technologies that allow them to expand the petroleum resource base over and over again. The pessimists focus on the questions: Just how long can this go on? How many additional places are there to look? As noted earlier in the section on "Resource Base Concepts," this history and the ongoing controversy in the search for petroleum is a paradigm for the development of many nonrenewable resources.

SOURCE: Dr. John Schanz, Senior Specialist in Energy Resources Policy, Congressional Research Service.

Table 10.—The Optimist's View of Gas Resources

- Just a few short years ago nobody had heard about the Overthrust Belt and the Tuscaloosa Trend; now everybody has jumped in. The pessimists have always been wrong about resource shortages.
- Increased prices for gas and better exploration techniques have opened up a huge new resource in small fields. Past estimates of the number of small fields relied on data from a time when a small field was likely to be abandoned as a dry hole.
- We haven't been looking for natural gas for more than a few decades, so a mature basin for oil—with little prospects for significant new finds—isn't necessarily mature at all for gas. This is especially true because the conditions that led to gas are often hostile to the formation and preservation of oil, and thus the presence of these conditions would have tended to keep explorers away. A key example of this effect is the deep gas resource.
- A good part of the lower finding rates of the recent past was due to the substantial increase in low-risk, low-yield drilling. The lower rates therefore do not necessarily imply "resource depletion."
- Most resource estimates—including optimistic ones such as those of USGS and PGC—represent only snapshots in time, reflecting current economics and technology. The resource base estimates will tend to grow over time as prices rise and technology advances.
- The decline in proved reserves of the past decade, interpreted by many as a sign of resource depletion, actually represents merely a rational response to high discount rates, that is, a reduction in inventory to the minimum amount necessary to sustain production.
- Recent price increases have opened up a large potential for new reserves from the growth of older fields. This new gas will come from closer spaced drilling, the extention of fields to lower permeability areas that were previously uneconomic, the lowering of abandonment pressures, and well workovers.

SOURCE: Office of Technology Assessment.

Table 11.—The Pessimist's View of Gas Resources

- We have drilled too many holes in the Lower 48 States and tested too many ideas to believe there is much room for brand new natural gas horizons.
- If there's so much gas right here in the Lower 48, why are we testing the limits of hostile environments in the Arctic and continental slopes?
- The geologists who make industry's resource estimates tend to be the most successful ones, those who have a built-in bias toward optimism because of their experience.
- We have already found most of the "easy," giant fields. The future is in the smaller reservoirs, and there doesn't appear to be enough of these to provide the amount of resources the optimists say is there.
- The depletion effects apparent in exploratory drilling finding rates are actually *understated* because the advance of exploration technology, by increasing the success rate of exploratory drilling, has tended to hide the onset of depletion.
- The higher resource estimates, when translated into the number of fields of various sizes that *must be discovered* to yield this much gas, look very shaky when compared to the numbers of these fields that we have actually been discovering lately.

SOURCE: Office of Technology Assessment.

is an acceptable range of estimates for the size of the recoverable resource base that excludes "unconventional gas"* and gas that cannot be exploited profitably at gas prices in the same range as today's and with technology that is well within reach in the next few decades? OTA believes that a substantial majority of scientists concerned about the gas resource base would feel comfortable *somewhere within*** a range that included Nehring's estimate as the extremely pessimistic minimum and the PGC estimate as not quite the maximum, but close to it. This range is about 280 to 915 TCF for the remaining conventional gas resource (including proved reserves and the growth of known fields) recoverable with readily foreseeable technology and given today's economics, for the Lower 48 States.

OTA believes that the minority who might like the range extended would consist mainly of those who believe that the upper end should be higher. Furthermore, OTA suspects that a thorough review of the production implications of the *lower* end of the range—as discussed in the next chapter—would tend to push many scientists away from this end of the range.* It should be added, however, that some of those who are considerably less optimistic than PGC, and even USGS, are major oil and gas producers—e.g., Exxon**—who are very familiar with most of the areas that are supposed to supply the United States with the "optimistic" levels of new gas discoveries.

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*Gas from very tight formations, geopressurized zones, coal beds, and Devonian shales. However, gas that arguably could be placed in these categories but that is commonly produced today, would be considered conventional.

**Many would no doubt disagree strongly with values near one extreme or the other, however.

*As shown in chapter 5, a 280-TCF remaining resource implies that the year 2000 production of Lower 48 conventional gas, recoverable with existing or foreseeable technology and at the current cost/price relationships, cannot be much greater than 4 TCF/yr.

**OTA has been told informally by Exxon geologists that Exxon's most recent internal estimates of the U.S. gas resource base are considerably below those of USGS and PGC. The major disagreements are with estimates for the Lower 48 onshore gas potential.

Box D.—Are the USGS and PGC Gas Resource Assessments Really Similar?

Two widely referenced gas resource assessments—those of the USGS and the PGC—have similar estimates for the ultimately recoverable gas in the Lower 48 (1,400 TCF and 1,542 TCF, respectively) and are often used to illustrate what some feel is a wide consensus for an optimistic gas future. Are these two assessments really so similar? The table below compares the *regional* assessments of undiscovered gas from both groups,* based on the PGC reporting areas.

PGC reporting area	*Onshore*		*Offshore*	
	PGC	*USGS*	*PGC*	*USGS*
A	41	11	16	24
B	13	21	30	3
C	3	6		
D	39	24		
E&G	34	101	52	69
H	159	124		
I	4	8		
J-N	99	43		
J-S	34	33		
L	16	19	18	7
Total**	442	390	116	102

The table shows some substantial disagreements about where the major undiscovered gas resources lie, but it also shows that, *on the average,* the region-by-region assessments agree quite well.

Important areas where the two agencies differ are:

- J-N—the mid-continent region (Kansas, Oklahoma, parts of Texas), where PGC is far more optimistic about deep gas.
- E&G onshore—the gulf coast.
- A—the Eastern Appalachian States.
- B offshore—Mississippi, Alabama, and Florida, where PGC remains optimistic about gas in the eastern Gulf of Mexico.
- D—Arkansas, north Louisiana, and central Texas.

The *average* level of agreement can be checked by conducting a linear regression of the two data sets. This yields a correlation coefficient of 0.74, which is a good agreement for two resource assessments conducted somewhat independently of each other.*** Also, removing the two worst disagreements—the offshore gulf coast and mid-continent estimates—increases the correlation coefficient to 0.92, a high value.

Consequently, the differences in no way "discredit" either of these assessments. The differences do illustrate, however, the substantial disagreements that can exist between two groups considered optimistic, and thus they illustrate the considerable uncertainty associated with these resource assessments.

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*The PGC values exclude "Probable" resources, which include new pools in discovered fields. Strictly speaking, PGC defines these pools as undiscovered; USGS does not, and includes them in its "inferred reserves" category.

**Excludes cumulative production, proved reserves, and growth of known fields.

***The estimators have too much access to the same studies and estimates, and to each other, to allow a claim of strict independence between the two assessments.

How Credible Are the Methods?

How credible the methods are is generally difficult to determine because few resource assessments using geologic approaches reveal many details of their assessment processes. Generally, more details are available for the assessments based on historical, extrapolative approaches; in addition, USGS makes available to the public its open-file reports and data. OTA did not attempt to review the extensive USGS backup information because of time and budget constraints. Historical approaches have been reviewed in a number of reports,[26] and for the most part OTA chose to use them instead of conducting a totally independent review.

In general, OTA is skeptical of historical approaches to resource assessment when they are based on national data and when they are the sole means of estimation. The substantial data problems associated with natural gas exploration (especially during those years when gas was valued as little more than a byproduct of oil production), the broad range of activity covered by any single data series, and the distorting effects of Government controls are important sources of this skepticism.

The most important estimate based strictly on a historical approach is Hubbert's because he has gained substantial credibility from his successful predictions of declining U.S. oil production. As discussed earlier in this chapter, OTA notes substantial problems with Hubbert's approach and believes that his extremely pessimistic estimate (870 TCF) of ultimately recoverable conventional gas is too low.

Of the assessments using geologic approaches, only the assessments of USGS and PGC are reviewable in any sense because details of the others are not public information. In OTA's opinion, both assessment processes are serious attempts to wrestle with a most difficult problem. One problem with both assessments is the failure to include the detailed assumptions behind, and implications of, the assessment, thus precluding much opportunity for useful feedback from those outside the assessment process. The USGS assessment may also be hampered by lack of access to proprietary industry data; PGC, on the other hand, apparently has access to excellent data but *appears* to ignore the insight that might be gained from analyses of discovery trends (i.e., the historic approach).

Are the Physical Implications of the Assessments Plausible?

Most gas resource assessments do not provide descriptions of either the direct physical implications of their resource estimates (e.g., the number and size of fields implied by the estimate) or, conversely, the initial physical model used to *derive* the estimate. Nevertheless, some physical implications can be drawn directly from the estimates. This is especially true when the estimates are separated into components: onshore and offshore (quite common), deep and shallow (e.g., the PGC assessment), and individual regions or even smaller provinces (USGS divides the United States into 137 separate provinces). Consequently, it is clear that PGC believes that the deep resource below 15,000 ft represents a massive source; fully 39 percent of the onshore undiscovered resource of the Lower 48 States is projected to be deep gas. In a similar vein, USGS clearly appears to have given up on the eastern Gulf of Mexico but has great hope—as does PGC—for another "frontier" area, the Western Overthrust Belt.

Rather than carrying out a detailed "translation" of each assessment, OTA chose to examine two basic physical issues that appear to cut across virtually all of the assessments. These issues, as stated by Nehring,[27] are:

- Does the assessment imply a substantial break with past and recent discovery trends and patterns?
- If the assessment does imply such a break, what is the explanation for it? Is it credible?

A Break With Past Trends?*

The most obvious ties between past trends and the magnitude of the resource base are the analyses performed in the "historic approaches" to resource assessment. In general, these approaches have given relatively pessimistic results when used with U.S. gas production and exploration data. For example, all four of the estimates using pure data-tracking techniques (two by Hubbert, one each by Wiorkowsky and Bromberg/Hartigan) in table 6 are below the USGS estimate, with three of the four at least 400 TCF below. In addition, the RAND estimate, which is at least partly dependent on past discovery trends, is nearly 500 TCF below the USGS estimates.

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[26] For example, Wiorkowski, op. cit.

[27] R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United States,* op. cit.

*Readers interested in past trends in petroleum exploration may also wish to read *Exploration for Oil and Gas in the United States: An Analysis of Trends and Opportunity,* by John J. Schanz, Jr. and Joseph P. Riva, Jr., of the Congressional Research Service (CRS report No. 82-138 S, Sept. 16, 1982).

This series of pessimistic resource estimates based on trend analysis, when coupled with the very low rates of reserve additions in the Lower 48 States from 1968 to 1978 (average yearly AGA reserve additions were 9.6 TCF v. average production of 20.6 TCF/yr), represent a strong initial argument that the more optimistic resource estimates do represent a break with past trends, while the pessimistic estimates do not. However, as noted in the discussion of historical approaches to resource assessment, the available data used to measure trends in exploratory success (or trends in other factors that may be used to form judgments about the probable size of the resource base) tend to measure multiple rather than single processes; for example, measures of the success of drilling for new fields are, in fact, measuring a range of activities from the high-risk testing of new geological ideas to the low-risk redrilling of formerly uneconomic dry holes. Consequently, none of these trends can be interpreted in an unambiguous manner. The discussions in chapter 5 about the factors that affect the various components of reserve additions give a sense of the complexity of individual trends and of the difficulties in interpreting the trends.

Trends in the discovery of new fields appear likely to be most closely associated with the remaining recoverable resource base; these trends are examined in the following paragraphs.

Table 12 displays the returns to new field wildcat drilling in the onshore Lower 48 States from 1966 to 1981. The patterns displayed in the table demand careful deciphering. The gas volumes found per successful gas new field wildcat show a startling decline during the period, from 18.56 billion cubic feet (BCF) per well in 1966 to 1.85 BCF per well in 1979 (use of EIA data moderates this trend somewhat, but the EIA and AGA data are not strictly comparable). *This means that the average field size found by a successful gas wildcat declined by a factor of 10 during 1966-79.*

Because the larger fields in a basin are generally found early in the discovery process, a sharply declining average field size is often interpreted as a sign that the discovery cycle is winding down. However, the data shown in the table are collected from multiple basins, and during the time period in question, the pattern of gas exploration may have been influenced by increased gas prices and other factors. For example, it is widely believed that deliberate exploration for small gas targets (e.g., in areas where past exploration identified then uneconomic gas deposits) increased sharply

Table 12.—Returns to New Field Wildcat Drilling in the Onshore Lower 48 States, 1966-81 (BCF/well)

	New field discoveries			
Year	Per all NFWs	Per new field discovery well	Per new gasfield discovery well	Percent of new field discovery wells that find gas
1966	0.46	4.56	18.56	25
1967	0.42	3.96	11.93	33
1968	0.24	2.66	10.25	27
1969	0.24	2.66	7.47	36
1970	0.29	3.01	8.20	37
1971	0.16	1.67	3.70	45
1972	0.24	2.11	4.46	47
1973	0.34	2.30	3.89	59
1974	0.24	1.60	2.88	56
1975	0.22	1.47	2.91	51
1976	0.18	1.02	1.85	55
1977	0.20 (.32)[a]	1.15 (1.86)	2.23 (3.61)	52
1978	0.17 (0.36)	1.07 (2.27)	1.96 (4.17)	55
1979	0.20 (0.26)	1.07 (1.40)	1.85 (2.48)	58
1980	(0.27)	(1.37)	(2.69)	51
1981	(0.34)	(1.88)	(3.95)	48

[a] AGA data (EIA data).

SOURCE: R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Date," contractor report to the Office of Technology Assessment, 1983.

during this period. Such an increase in the willingness of explorationists to go after small targets would tend to reduce field size averages *even if high-risk exploration for large fields maintained a steady success record.* Consequently, the decline in average field size may not fairly represent the actual condition of the resource base.

The record of returns to wildcat drilling *per well drilled* tends to support this view. These returns per well drilled have exhibited only a slight decline since 1968; the success rate, which varies from a low of 2.3 percent in 1968 to a high of 10.8 percent in 1979, essentially compensates for the declining field size. In other words, *while each gas wildcat well completed returned far less gas in 1979 than in 1966, the actual number of wildcat wells drilled to find each trillion cubic feet of gas did not increase very much during this period.* This relatively optimistic result should be tempered, however, by the observation that the percentage of wildcats aimed deliberately at gas targets probably increased during this period. Consequently, it is likely that the actual gas-directed effort—as distinct from the total *petroleum*-directed effort—that was needed to find a unit of gas probably did increase during the period.

Although the data in table 12 look more optimistic than might have been initially expected, the history of natural gas development implies that, in order to sustain successful levels of reserve additions for the long-term, efforts must be made to open new geologic horizons and find the large fields that are the cornerstone of reserve growth in later years. Consequently, it is useful to examine the pattern of discovery of different-sized fields.

The American Association of Petroleum Geologists (AAPG) publishes the primary public record of the discovery of petroleum fields by size and discovery year, and this record may be used to examine patterns of discovery. The record must be used cautiously, however, because AAPG appears to have undercounted the number of fields discovered.* For example, from 1971 to 1975, AAPG reports only 49 gas discoveries of a size greater than 60 BCF. In comparison, the RAND data base reports 141 fields in this size range during the same time period.[28] Consequently, the AAPG data should be examined for trends rather than absolute magnitude, and even the trends may be skewed if undercounting and other problems were not consistent over time.

Table 13 presents the historical record of new gasfield discoveries by field size, for 1945-75, as compiled by AAPG.* In parallel with the trends shown in table 12, the percent of significant (size class A through D) gasfields in all gas discoveries decreased over the 30-year period, while the effort required to find a significant field increased through the 1960's but then declined to earlier levels.

The data in the table can be used to examine the discovery trends of larger fields. Figures 11 and 12 show trends in, respectively, the number of fields discovered as a percentage of new field wildcats drilled, and the number of fields discovered per year. Figure 11 shows that the apparent effort (in wells drilled)** required to find fields of size C or larger, B or larger, and A grew sharply during the early 1950's but then leveled off between 1955 and 1975. However, these trends would look considerably more pessimistic if "total footage" rather than "wells drilled" were the measure of effort. This is because the average depth of new field wildcats grew steadily during this period, from 4,007 ft in 1946 to 6,071 ft in 1975.[29]

Figure 12 shows that, starting about 1950, the number of moderate-to-large gasfields declined steadily through 1975. These larger fields may be particularly important for continued reserve additions because of the general belief that the larger fields generate the majority of field growth (from extensions, new pool discoveries, and revisions).

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*Part of this problem may arise from simple disagreements over field boundaries; the EIA data base, for example, treats the Hugoton field as three separate large fields, whereas other analysts might count it as one. Also, field reserve estimates are not consistent across data bases.

[28] R. Nehring, *Problems in Natural Gas Reserve, Drilling, and Discovery Data,* contractor report to OTA, 1983.

*The record stops in 1975 because AAPG classifies fields as gas or oil fields only after the passage of 6 years past the discovery report.

**"Apparent" because some of the wells were aimed deliberately at small targets and should not be included in the "effort" involved in finding large fields. As noted, however, there is no way to separate data about these wells from the overall data.

[29] R. R. Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin,* vol. 66/11, November 1982.

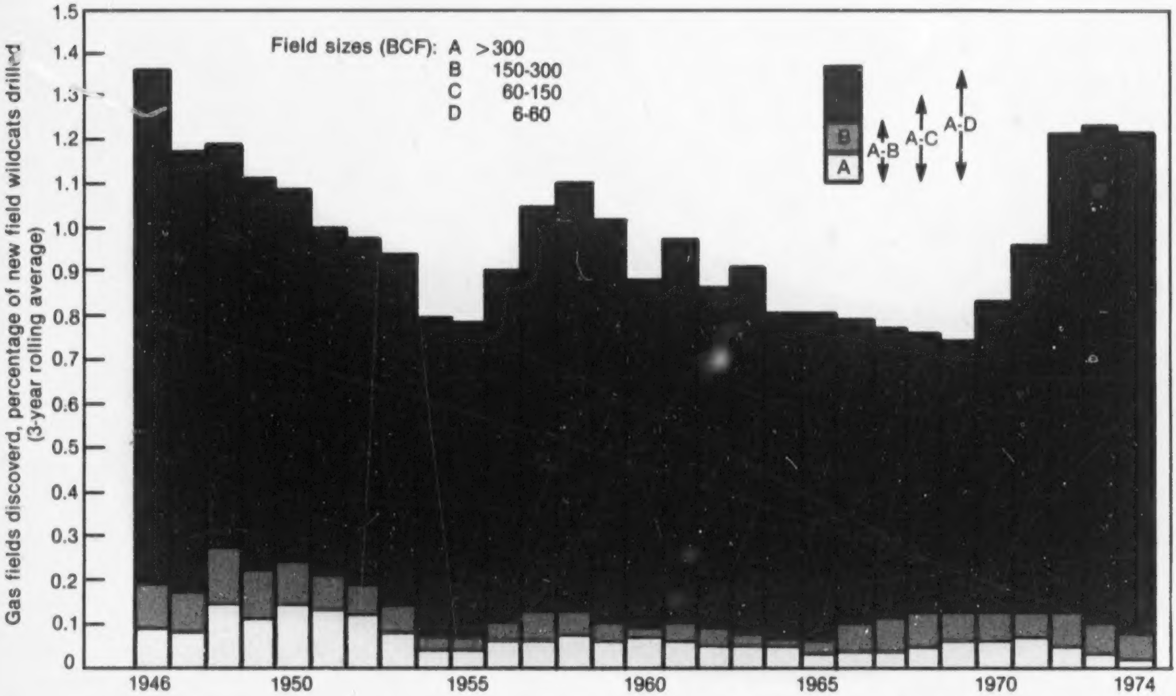
Table 13.—Historical Record: Number of New Gasfield Discoveries Proved After Six Years To Be of Significant Size

Year drilled	Total wells reported as gas wells at end of year of completion	Number of fields in each size classification[a] after 6 years development history							Total significant size gasfields	Percent of significant gasfields in all gas discoveries	Total new field wildcats drilled	Percent of significant gas finds in total new field wildcats drilled
		A	B	C	D	E	F	Total	A-D Inclusive (A+B+C+D)			
		Significant										
1945	103	3	2	11	33	24	20	93	49	52.69	2,905	1.69
1946	78	1	2	7	22	29	12	73	32	43.84	2,995	1.07
1947	106	5	5	4	30	35	19	98	44	44.90	3,325	1.32
1948	116	3	3	7	33	35	19	100	46	46.00	4,087	1.13
1949	121	8	7	8	34	43	12	112	57	50.89	4,238	1.34
1950	118	4	4	8	28	44	19	107	44	41.12	5,149	0.85
1951	155	10	4	10	41	57	16	138	65	47.10	6,044	1.08
1952	171	10	7	7	44	65	15	148	48	45.95	6,440	1.06
1953	177	3	3	6	40	89	18	159	52	32.70	6,634	0.78
1954	248	4	1	12	51	104	39	211	68	32.23	7,033	0.97
1955	228	2	3	11	33	107	43	199	49	24.62	7,743	0.63
1956	230	2	4	5	52	92	26	181	63	34.81	8,436	0.75
1957	247	9	5	15	70	105	30	234	99	42.31	7,556	1.31
1958	262	3	6	9	55	143	25	241	73	39.29	6,618	1.10
1959	308	4	1	6	51	135	28	225	62	20.13	7,031	0.88
1960	240	6	2	9	63	135	22	237	80	33.76	7,320	1.09
1961	316	4	3	4	35	156	40	242	46	18.59	6,909	0.66
1962	317	3	4	11	61	161	52	292	79	27.05	6,794	1.16
1963	240	4	1	7	38	124	41	215	50	23.26	6,570	0.76
1964	252	4	1	11	37	136	37	226	53	23.45	6,623	0.80
1965	234	1	3	10	38	142	30	224	52	23.21	6,175	0.84
1966	232	1	3	7	36	142	12	201	47	23.38	6,158	0.76
1967	179	4	5	6	26	111	12	164	41	25.00	5,271	0.78
1968	126	1	5	7	27	83	14	137	40	29.20	5,205	0.77
1969	190	3	2	4	35	116	14	174	44	25.28	5,956	0.74
1970	184	5	4	3	25	79	14	130	37	28.46	5,069	0.72
1971	202	2	3	3	38	102	12	160	46	28.75	4,463	1.03
1972	273	3	2	6	47	187	0	245	58	23.67	5,086	1.14
1973	416	2	6	10	57	284	0	359	75	20.89	4,989	1.50
1974	445	0	2	6	51	329	0	388	59	15.21	5,652	1.04
1975	448	3	0	1	64	336	0	404	68	16.83	6,104	1.11

[a]Size classifications: A = >300 BCF
B = 150-300 BCF
C = 60-150 BCF
D = 6-60 BCF
E = <6 BCF
F = noncommercial

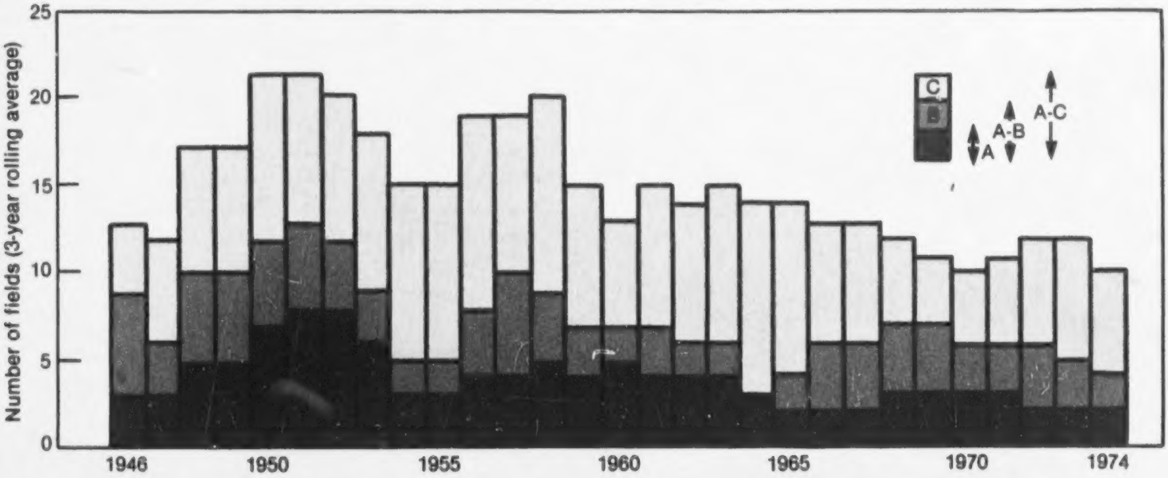
SOURCE: R. R. Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol. 66/11, November 1982.

Figure 11.—Number of Gasfields Discovered As a Percentage of New Field Wildcats Drilled, by Field Size Grouping



SOURCE: Office of Technology Assessment, based on data from table 16 in R. R. Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol. 66/11, November 1982.

Figure 12.—Number of Gasfields Discovered per Year, by Field Size Grouping



SOURCE: Office of Technology Assessment, based on data from table 16 in R. R. Johnston, "North American Drilling Activity in 1981," *AAPG Bulletin*, vol. 66/11, November 1982.

The impression gained from table 12 and figures 11 and 12—that finding rates for the small-to-moderate sized fields have held up very well and even increased, but that rates of finding the larger fields have declined somewhat over the past few decades—is reinforced by an examination of Lower 48 gasfield discoveries of 1 TCF and larger. Such discoveries were scattered throughout the 1916 through 1966 period, with particularly large discoveries* in 1916 (Monroe, La., 9 TCF), 1918 (Hugoton, Kans./Tex./Okla., 36 TCF and Panhandle, Tex., 31 TCF), 1921 (San Juan, N. Mex., 18 TCF), 1928 (Jalmat, N. Mex., 6 TCF), 1934 (Katy, Tex., 7 TCF), 1936 (Carthage, Tex., 6 TCF), and 1952 (Puckett, Tex., 4 TCF).[30] However, according to the 1977 International Petroleum Encyclopedia,[31] no gasfields larger that 4 TCF were found between 1953 and 1967, and no gasfields larger than 1 TCF were found between 1967 and 1975.**

The trends in discovery up to the middle 1970's, although rendered somewhat ambiguous by the nature of the data, appear to support two conclusions. First, they show that exploration trends for gas have not nearly been as much a cause for pessimism as have oil exploration trends; in short, they do not show why the resource pessimists such as Hubbert predict such a radical drop in new discoveries. The rate of discovery of significant fields (fields of sizes A through D) did not experience the kind of steep decline that would seem to be a prerequisite for predicting—as the Hubbert resource estimate does—that undiscovered resources now total only 100 TCF. Second, the trends indicate that the type of fields usually associated with opening up major new horizons were not being discovered and that more and more of the new fields appeared to be coming from further along in the discovery cycle. The limited number of giant fields discovered in this period gives some cause to question the relatively optimistic estimates of USGS and PGC.

As to recent trends, the recent upsurge in total reserve additions has been the common centerpiece in arguments that the "resource optimists" have been right all along. Questions are raised about whether recent large discoveries in the deep Anadarko Basin and in the Overthrust Belt signify a reversal of the long-term, more pessimistic trends.

In OTA's opinion, responsibility for the reserve additions of the past few years—and therefore the implications for *future* reserve additions and production—cannot be assigned to a particular cause without a detailed investigation, at the level of individual fields and entrepreneurs, of the precise nature of the increases. Such an investigation would attempt to determine whether the new reserve additions represent a true turnaround in the exploratory process or a one-time surge of reserve development caused by the sudden movement from the subeconomic into the economic range of a limited inventory of known prospects and an acceleration of the normal pace of field development. OTA has not seen any convincing analyses arguing one side or the other.

As for the Overthrust Belt and Anadarko, the future of these areas is uncertain. The Overthrust Belt did produce some very large new fields in the late 1970's (the Whitney Canyon/Carter Creek and East Anschutz Ranch fields appear to have resources greater than 1 TCF), and its potential is substantial. However, despite continued searching, no new giant fields have been discovered in the past few years. In the Anadarko, the recent declines in prices for deep gas may have moved some gas from "economic" to "subeconomic," although the earlier superheated market for this gas and the resulting distortions in prices and production costs make it difficult to predict where the economic/subeconomic boundary might lie in the future. Also, recent engineering difficulties and rapid pressure declines in some fields imply that some overestimates may have been made in calculating reserves and estimating resources.

In conclusion, in OTA's opinion **the gas discovery trends of the past several decades, while**

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*Some of these fields—Hugoton, Panhandle, San Juan—are considered multiple fields by some analysts, one field by others. Also, there is considerable variation in reserve estimates from one source to another.

[30] Oil and Gas Resources Data System, Energy Information Administration; and J. McCaslin (ed.), *International Petroleum Encyclopedia*, vol. 10 (Tulsa, Okla.: Petroleum Publishing Co., 1977).

[31] McCaslin, op. cit.

**It is possible, however, that further growth of fields that were below the 1 TCF level in 1977 could have moved them into the "greater than 1 TCF" category in later years.

not supporting the most pessimistic of the recent gas resource estimates, also do not support the relatively optimistic estimates of PGC and, possibly, USGS.

Some Alternative Explanations

The (until recently) moderately pessimistic discovery trends and optimistic resource base estimates can be reconciled by two possible arguments:

- It is not the resource base but the market distortions caused by Government regulations that have caused discovery trends to be disappointing. Exploratory incentives have been skewed toward low-risk, low-payoff gas prospects.
- The historical trends do represent the depletion of traditional sources of natural gas. Now, however, improved technology and higher prices will allow explorers to find large quantities of gas from:
  - —small fields;
  - —reworking of older fields;
  - —new frontiers, including deep gas; and
  - —subtle stratigraphic traps.

The Causes of Past Trends

Is it the *nature of the remaining resource base* that has been the primary influence on historical declining trends in new field discoveries, or was it instead the *economic and regulatory environment* that provided the controlling influence? Does the relatively low rate of discovery of large new gasfields during the last decade and a half reflect resource depletion, or are these rates an artifact of the erratic price and regulatory history of natural gas? If gas resources are substantially depleted, it appears unlikely that gas finding rates and discoveries of large new fields will rebound to levels that would sustain high production rates. If the economic/regulatory history of gas is the cause, then optimism about future production potential may be well founded, assuming that economic and regulatory conditions can be made favorable to the gas discovery process.

The basic argument that low finding rates for new fields and other warning signals do *not* reflect resource depletion centers around the idea that the rigid price controls of the period before passage of the Natural Gas Policy Act of 1978 (NGPA) locked drilling into lower cost and risk areas that do not coincide with where the major gas potential resides. The "culprit" for this is said to be the method used by the old Federal Power Commission (FPC) to calculate allowable "area" and "national" gas prices. FPC assumed that future exploratory and development costs would be similar to past average costs, and by basing the allowable price on this assumption, essentially *guaranteed* that drilling would be confined to areas where costs were expected to be low.

A past proponent of this view has been the American Gas Association. AGA has conducted a series of studies[32] comparing total gas well completions to estimates of gas resource potential* in the Outer Continental Shelf, Alaska, the shallow Lower 48 area, and deep (below 15,000 ft) horizons. Their September 1979 analysis, which includes drilling data through 1977, concludes that "the drilling data suggested that *the decline in proved reserves was not due to a depletion of gas sources but rather to a lack of economic incentives for drilling under an artificially constrained, regulated environment [emphasis added].*"[33] This conclusion was based on the poor correlation of gas well completions to gas resource potential detected in the study** (see the first two circle charts in fig. 13). However, a more recent (January 1981) analysis added a comparison of gas well *expenditures* to gas resource potential (third circle chart in fig. 13). Noticing a *good* correlation of expenditures to resource potential,*** AGA omitted the earlier conclusion and attributed the imbalance between drilling and potential to "the much lower cost-per-well and cost-per-foot figures for the shallow, Lower 48 wells."[34] The very high drill-

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[32] The latest is AGA, "Gas Well Drilling Activity and Expenditures in Relation to Potential Resources," *Gas Energy Review*, vol. 9, No. 1, January 1981.

*The measure used for "Resource Potential" was PGC's estimates of potential supply.

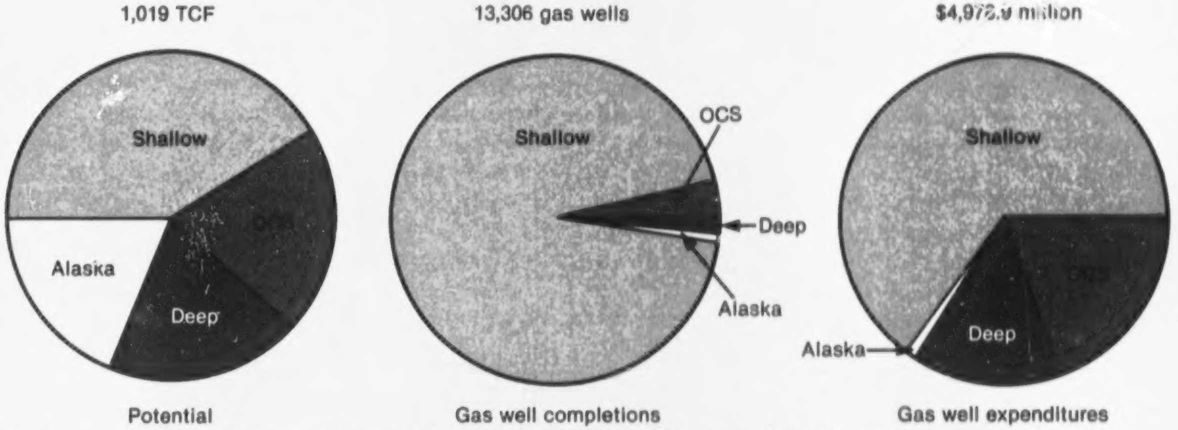
[33] AGA, "Drilling Activity and Potential Gas Resources," Gas Energy Review, vol. 7, No. 11, September 1979.

**Of course, an alternative reason for the poor correlation could be that gas entrepreneurs do not agree with AGA's view about where the resource potential lies.

***Except for Alaska, where lack of a transportation system blocks gasfield development.

[34] AGA, "Gas Well Drilling and Expenditures . . . .," op. cit.

Figure 13.—Gas Potential, Gas Well Completions, and Expenditures—1978



NOTE: "Shallow" and "deep" refer to Lower 48 States onshore; "potential" is based on PGC's estimates of the undiscovered gas resource.

SOURCE: "Gas Well Drilling Activity and Expenditures in Relation to Potential Resource," in *Gas Energy Review*, vol. 9, No. 1 (Arlington, Va.: American Gas Association, January 1981).

ing costs and risks of the high gas potential frontier areas necessitate a very cautious attitude toward drilling, whereas the lower costs in developed onshore areas encourage closely spaced development drilling and exploratory drilling for small reservoirs and other marginal targets.

A corollary to the argument about the effects of low allowable gas prices is used to explain why the sharp price increases of the past several years have not improved the rate of new field discoveries. According to this view, drilling priorities will not immediately be corrected by rising prices because the long period of controls has created a large backlog of low-risk, previously marginal exploration prospects that are now commercially viable. Until this backlog is reduced, the argument goes, exploratory drilling will stay away from the high-risk, high-payoff wells that could find the large fields[35] that now only appear to be scarce. Furthermore, because price increases expand the boundaries of the "economically recoverable" resource base and thus add to the inventory of low-risk prospects, it is claimed that the trend toward low-risk, low-payoff drilling is likely to continue if prices continue rising.[36]

High-risk, high-payoff drilling may be expected to yield low success rates. Consequently, the sharply *improved* success ratios of both total exploratory drilling and new field wildcat drilling during the past decade and a half, shown in table 14 and figure 14, has been used to support the thesis that drilling is skewed toward the low-risk targets. The overall success rate of these drilling categories may be affected by a variety of factors, however, that cannot be separated out. For example, substantial progress in improving exploration techniques and computer technology during this period undoubtedly acted to increase success rates, but to an unknown degree.* Also, the success rate is automatically elevated by the decrease in minimum acceptable field sizes and gas flow rates associated with increased gas prices; small fields and low-permeability reservoirs that in the past would have been considered "dry" are now being developed as producers. Therefore, it is quite conceivable that an increase in *overall* success rates could be accompanied by an increase in high-risk drilling if the other factors affecting success rate were strong enough to overcome the negative effects of the shift in risk.

In addition to arguments about the effects of price controls, some analysts point out that

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[35] Jensen Associates, Inc., "Early Effects of the Natural Gas Policy Act of 1978 on U.S. Gas Supply," report to the Office of Oil and Natural Gas, U.S. DOE, April 1981.

[36] R. P. O'Neill, "Issues in Forecasting Conventional Oil and Gas Production," in *Oil and Gas Supply Modeling,* National Bureau of Standards Special Publication 631, May 1982.

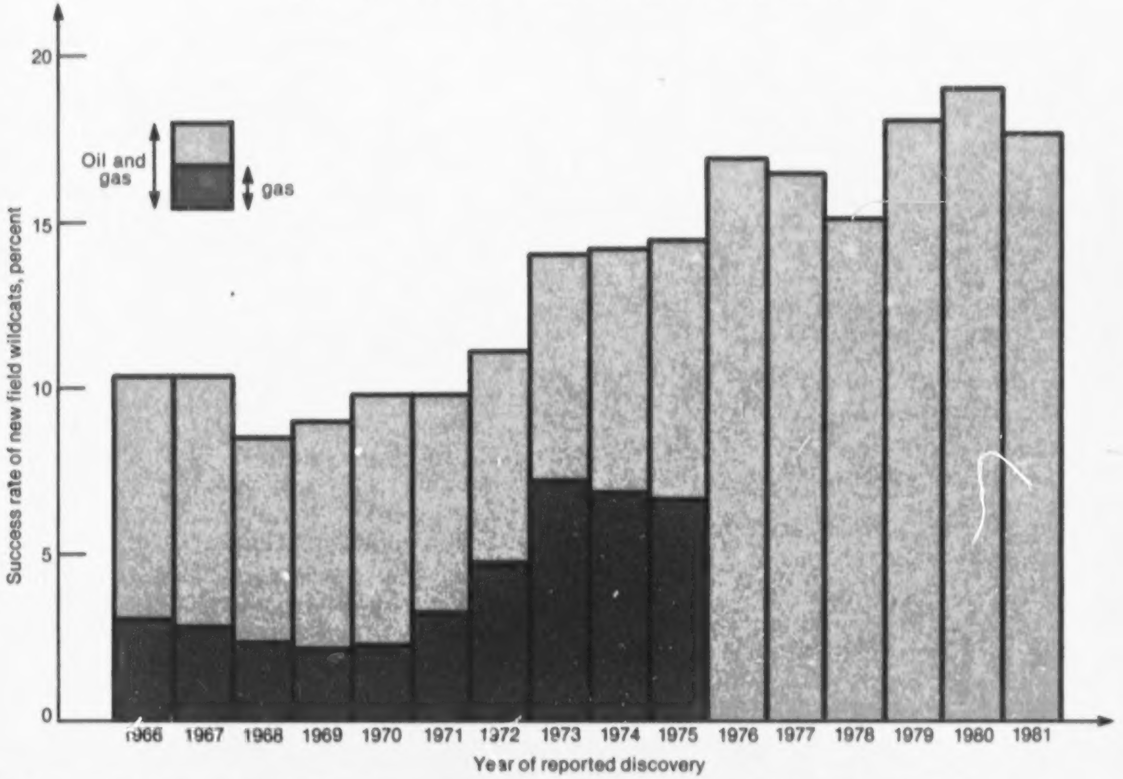
*The extensive investigation of the effects of new technology by the National Petroleum Council in 1965 could find no credible quantitative measurement of these effects.

Table 14.—Oil and Gas Drilling Success Rates (discoveries as a percentage of exploratory drilling effort)

	Exploratory wells			"Wildcats"		
Year	Completed	Total	Rate	Completed	Total	Rate
1966	1,894	10,313	18.4%	635	6,158	10.3%
1967	1,518	8,878	17.1	544	5,271	10.3
1968	1,440	8,879	16.2	442	5,205	8.5
1969	1,700	9,701	17.5	535	5,956	9.0
1970	1,271	7,693	16.5	493	5,069	9.7
1971	1,088	6,922	15.7	436	4,463	9.7
1972	1,285	7,539	17.0	566	5,086	11.1
1973	1,519	7,466	20.3	701	4,989	14.1
1974	2,009	8,619	23.3	805	5,652	14.2
1975	2,143	9,214	23.3	876	6,104	14.4
1976	2,449	9,234	26.5	986	5,840	16.9
1977	2,686	9,961	27.0	1,004	6,101	16.5
1978	2,728	10,677	25.6	983	6,505	15.1
1979	3,024	10,484	28.8	1,162	6,413	18.1
1980	3,574	11,916	30.0	1,340	7,034	19.0
1981	4,585	15,168	30.2	1,423	8,052	17.7
1982	4,847	16,470	29.4	1,400	7,912	17.7

SOURCE: American Petroleum Institute, "Quarterly Review of Drilling Statistics."

Figure 14.—New Field Wildcat Success Rate, 1966-81



NOTE: Gas success rate data not available after 1975 because gasfields and oilfields are separated out only after a 6-year review by AAPG.

SOURCE: Office of Technology Assessment, based on data from American Petroleum Institute, Quarterly Review of Drilling Statistics.

maintenance of high levels of proved reserves in relationship to production would not be compatible with good business practices. According to this argument, high-interest rates made it sensible for gas producers to reduce their standing inventory—i.e., proved reserves—by maximizing deliverability and reducing exploration. Consequently, from the drilling low point of 1971 to 1982, developmental drilling rose by a factor of 3.66 (18,929 wells drilled v. 69,330), whereas total exploratory drilling rose by only a factor of 2.38 and new field wildcats rose by only 1.77.[37] Carrying this argument further, the economic incentive to increase reserves will occur only when the cost of reducing R/P ratios—of adding to the deliverability of current reserves—outweighs the cost of adding new reserves.

Although the argument about the lack of an economic incentive to increase reserves is a fair one, it does not take into account the incentive for exploration provided by a number of factors, including the perception in the industry that the rapid declines in reserve levels were dangerous and should be halted if possible, the continued profitability of most larger gasfields even at low prices, and the former inseparability of gas and oil exploration, which allowed gas discovery to benefit from exploration incentives provided by oil.

The argument about the real cause of the downward trends of past decades is difficult to resolve because the opposing sides are generally arguing less about the data themselves than about their *interpretation*. Both sides agree, for example, that onshore gas exploration has become increasingly oriented to prospects with less "dry-hole" risk but with smaller reservoirs with poorer producing characteristics. Those arguing for resource depletion believe, however, that this trend has occurred primarily because *that is the nature of the remaining resource base;* those arguing for a more optimistic view of resources argue that the trend reflects a natural market response to early controlled prices, recent price increases, and high discount rates that favor production over inventory. Undoubtedly, both arguments are valid to some degree; the problem is in determining the relative importance of each.

Potential Major Sources of Additional Gas

Small Fields.—One basic argument revolves around the question of whether or not a sizable resource—large enough to support continued high rates of production—lies in fields containing 60 BCF of gas or less. The source of the argument lies in the shape of the field size distribution curve.

Historically, the cumulative number of gas and oil fields are distributed according to size in a manner shown in figure 15. In this figure, the size classes 1 through 20 (on the *x* axis) are scaled so that the upper limit of size class 20 is one-half the upper limit of 19, and so on. As shown in the figure, the cumulative number of fields increases with decreasing size class as a geometric series, down to about size class 13 (or class D in the AAPG notation), and then rapidly levels off. At least a portion of this "truncation," or leveling-off, of the field size distribution is undoubtedly due to past economics; many small finds were too small to be economically developed and consequently were reported as dry holes rather than added to the historical record as a class D or E field. Because pipeline gathering systems are required in order to develop gasfields no matter what the field size, and also because the price (per unit of energy) of gas has historically been lower than that of oil, the minimum field size suitable for development is larger—and thus the truncation described above is more severe—for gas than for oil. The crux of the current argument is, simply, what will the shape of the field size distribution curve look like when the effects of higher gas prices run their course? An important corollary to this argument is, how expensive will it be to discover and develop these small fields, and, consequently, how many of them can appropriately be included in the recoverable gas resource base?

Proponents of the thesis that small fields represent a very sizable resource argue that the trend observed for fields larger than size class D— i.e., a progressive increase in the number of fields discovered in each size class as one moves from the larger field sizes to the smaller—will be continued into the small field sizes below class D once these fields are made the target of intensive exploratory efforts. This argument maintains that the tailing-

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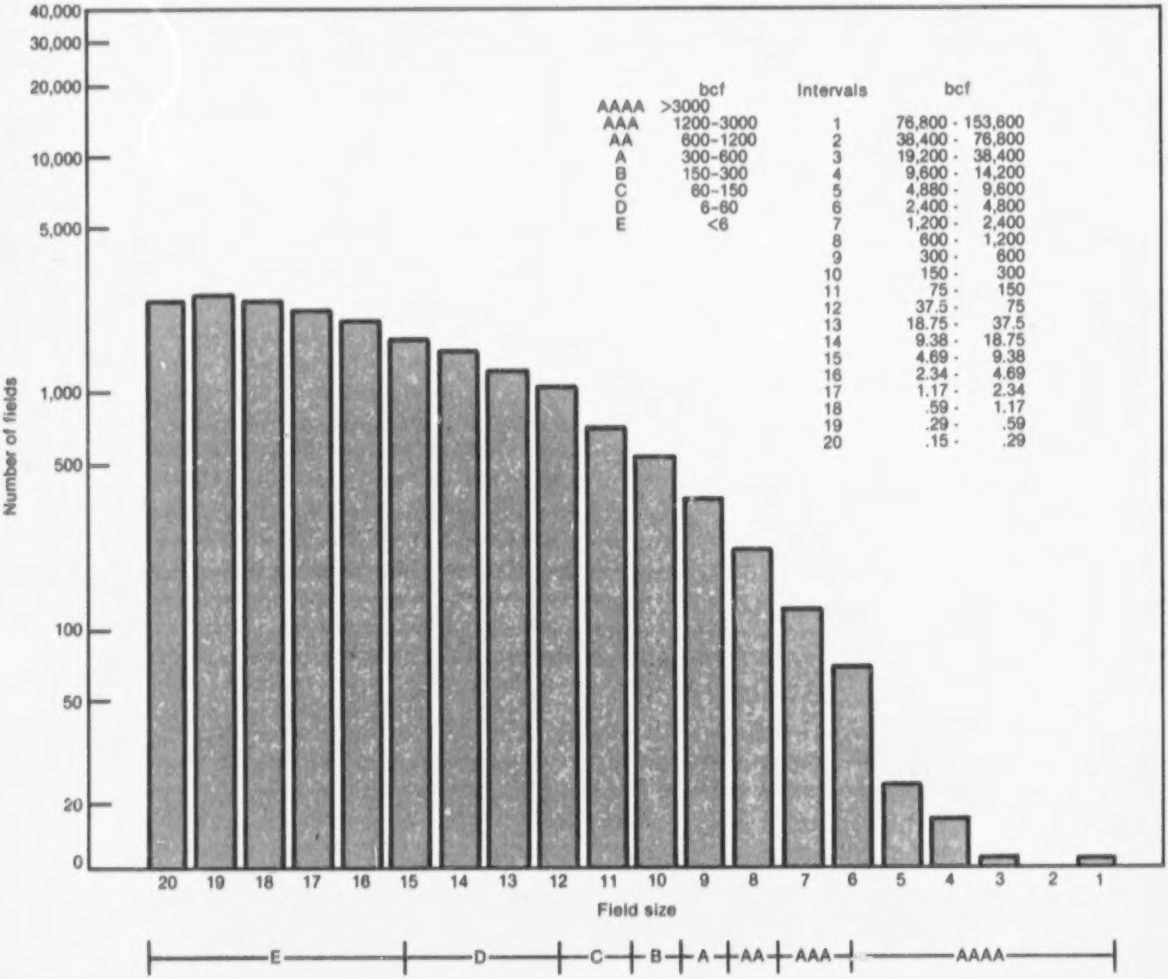
[37] American Petroleum Institute, "Quarterly Review of Drilling Statistics."

Figure 15.—Size Distribution of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

off of the curve in figure 15 is almost entirely the result of economics and that there are no geologic reasons for the drop in the number of very small fields. Scheunemeyer and Drew,[38] in examining field size distributions in the Gulf of Mexico and the Denver Basin and at three depth intervals in the Permian Basin, show that the "truncation point" of the field size distribution moves to larger field sizes when exploration and development costs are higher, which would be expected if the truncation were economically determined. Also, they note that the point moved to smaller field sizes after gas prices rose and the minimum profitable field size became smaller.

A straightforward argument against the "small fields thesis" is that estimates of large resources from small fields cannot be based on more than an assumption or extrapolation—because no petroleum basin has experienced the intensity of drilling that would be required to find the postulated number of small fields. This argument appears to be a powerful one, but it works equally well against those who might deny the possibility of large numbers of small fields. It probably is not possible at this time to estimate credibly the ultimate number of small gasfields remaining to be discovered in the United States and the resources these fields represent.

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[38] J. H. Scheunemeyer and L. J. Drew, "A Procedure to Estimate the Parent Population of the Size of Oil and Gas Fields as Revealed by a Study of Economic Truncation," *Mathematical Geology*, vol. 15, No. 1, 1983.

A second argument that has been presented is that, in some basins, the field size truncation does not appear to be generated by economics and is more likely to have been caused by geology—the simple lack of sufficient small fields. For example, Nehring[39] identifies subduction and delta provinces,* that account for more than one-quarter of U.S. oil and gas resources, as an example of basins where the number of fields in each size category begins to drop at a size level considerably above any historical field size minimum. Nehring argues that only a portion of U.S. provinces act according to Scheunemeyer and Drew's thesis and that there are four distinct groupings of field size distributions, ranging from one with a rapid increase in the number of fields with decreasing field size (similar to those discussed by Scheunemeyer and Drew), to one with a single peak at about size class D, to one with little increase in the number of fields at field sizes below A or B.

A third argument notes that it takes about 1,000 class E fields to equal three class A fields,[40] and that even a sharp increase in the number of small fields discovered may not be of major significance to the overall resource base. Figure 16 shows the known field size distribution, as in figure 15, and two projected distributions for the ultimately recoverable resource base—one that assumes a doubling of the approximately 24,000 fields known as of 1975, with most of the increase at the smaller sizes, and a second that assumes a much larger increase at the smaller field sizes, essentially by assuming that the truncation of the number of fields at smaller sizes is *entirely* an effect of economics and that the actual number of fields continues to increase logarithmically with decreasing field size.* The first projection produces 48,000 fields, the second about 115,000. Of critical importance is the *difference in resources* between the two projections, all of which arises from different assumptions about how the existing truncation of small fields will "fill in" with future discoveries; it is about *7 percent* of the total resource base represented by the second projection. Extrapolating to the gas resource base (and assuming the "central tendency" range of 902 to 1,542 TCF of ultimately recoverable resources), the assumption that the *ultimate* number of small gasfields found will be much larger than indicated by the historical field size distribution might lead to an increase in OTA's estimates of potential gas resources of approximately 60 to 110 TCF.

A fourth argument notes that the small size of the fields makes them only marginally economic at best. For gasfields, especially, many of the fields in the projected distributions may not be economic at current and projected gas prices and therefore may not belong in the recoverable resource base at this time.** In partial support of this argument, USGS studies the effect of gas price and other economic variables on recoverable gas resources in the Permian Basin indicate considerable sensitivity of the size of the remaining resource to these variables. Table 15 presents estimates of the amount of exploratory drilling that could profitably be pursued and the gas resources that would be discovered by this drilling as a function of wellhead price. *If the model used by the study is correct,* the size of the recoverable resource in small fields is sharply sensitive to price (also rate-of-return), although the sensitivity declines at gas prices above $5 to $6 per MCF.

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[39] R. Nehring, *The Discovery of Significant Oil and Gas Fields in the United States,* R-2654/1-USGS/DOE, RAND Corp., January 1981, pp. 78-94. Excursus, The Distribution of Petroleum Resources by Field Size in the Geologic Provinces of the United States.

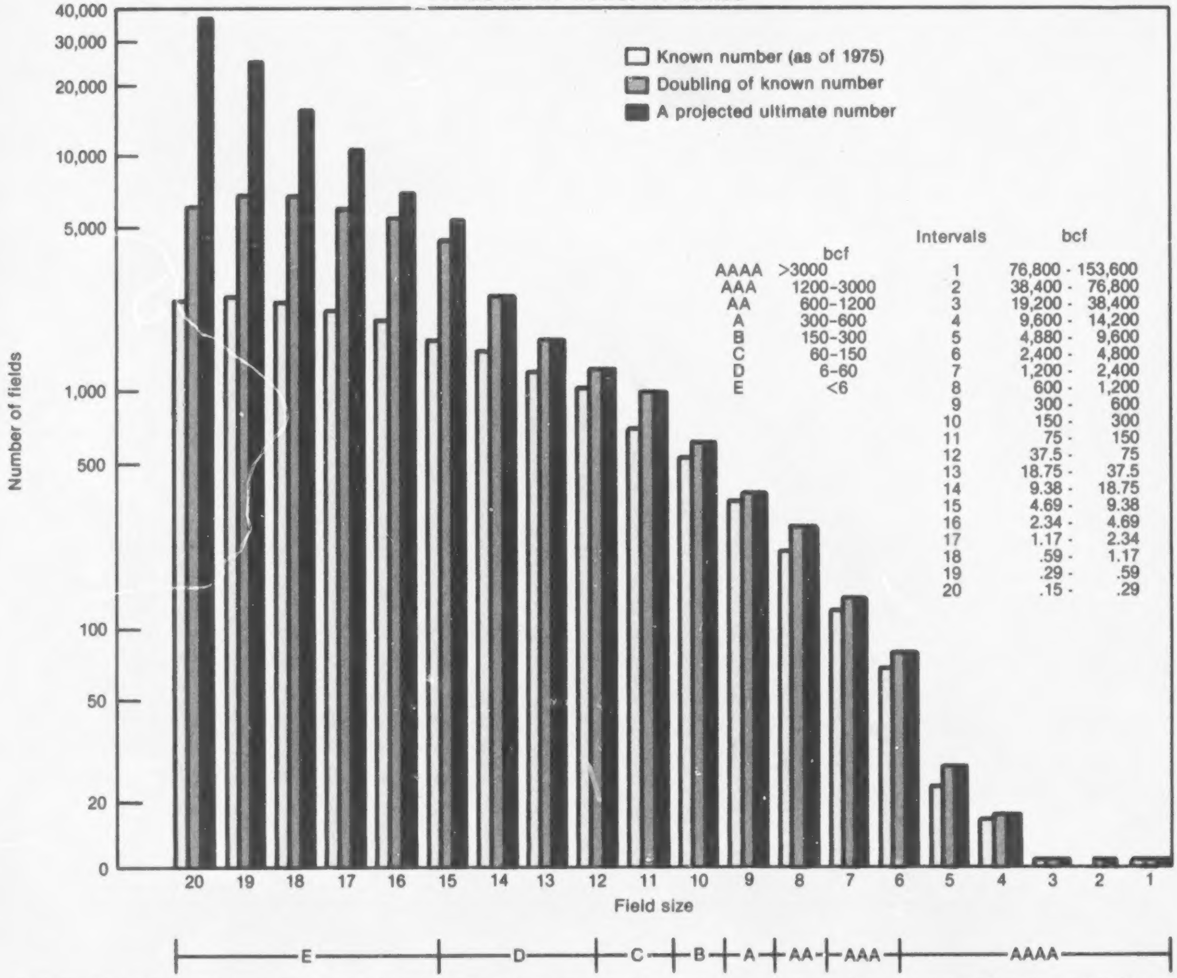
*Subduction provinces are small, linear basins located along the converging margins of plates. They account for about 11 percent of U.S. oil and gas resources in the RAND assessment. The three largest are the San Joaquin, Los Angeles, and Ventura provinces on the west coast. Delta provinces are small-to-medium sized, circular-shaped, and derived from major continental drainage centers. The one producing delta province in the United States is the Mississippi Delta, which accounts for about 17 percent of U.S. oil and gas resources in the RAND assessment.

[40] R. Nehring, *Problems in Natural Gas Reserve, Drilling, and Discovery Data,* op. cit.

*The projected distribution is drawn by assuming that the number of fields in each size interval smaller than 100 million BOE (0.6 TCF) is 50-percent greater than the number of fields in the next larger interval.

**In other words, they are subeconomic resources in the McKelvey Box (fig. 8).

Figure 16.—Known and Projected Size Distributions of Discovered Oil and Gas Fields in the Lower 48 States



SOURCE: Office of Technology Assessment, based on data from R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

Table 15.—Potential Recoverable Gas Resources From New Discoveries in the Permian Basin (assumed 15 percent of return)

Wellhead price $/BOE ($/MMBtu)[a]	Exploration wells drilled (thousands)	New discoveries (TCF)
10 (1.50)	5	4.98
15 (2.40)	12	9.17
20 (3.20)	18	11.38
25 (4.00)	24	13.02
30 (4.80)	29	14.12
35 (5.60)	34	15.13
40 (6.40)	38	15.81

[a] Dollars per barrel of oil equivalent (dollars per million Btu).

SOURCE: Geological Survey Circular 828—Future Supply of Oil and Gas From the Permian Basin of West Texas and Southeastern New Mexico, Interagency Oil and Gas Supply Project, 1980.

New Gas From Old Fields.—Over the lifetime of a field, from initial discovery to depletion, estimates of the field's ultimately recoverable resources generally increase with time as normal development probes the full extent of the field and as improved technology and rising prices bring subeconomic portions of the field into the economically recoverable range.* Although the effects of improved technology and prices have long been acknowledged as critical for increasing oil recovery, gas recovery rates have long been considered to be very high under most conditions and thus somewhat insensitive to price and technology.* Consequently, increases in reserve estimates from known gasfields were generally considered to be primarily an effect of the normal process of exploring for new pools and enlarging the proved area of known pools. This view is now being challenged, as reserve additions are being credited to lowering of the abandonment pressure of depleting reservoirs, to extension of field boundaries into areas of low permeability, to well stimulations and well reworking, and to infill drilling to well spacings lower than the old norm of 640-acre spacing (see box E). For example, from 1969 to 1979, ultimate recovery in the Hugoton-Panhandle field (discovered around 1920) in Kansas, Oklahoma, and Texas Railroad Commission District 10 increased from 71.0 to 84.0 TCF,** and ultimate recovery in the Blanco-Basin fields (discovered from 1927 to 1950) in the San Juan Basin increased from 15.2 to 21.7 TCF.[41] Although growth rates of known fields have varied considerably across different geographic areas, these substantial increases in known recovery from quite old fields are well beyond what might have been predicted by the historic data on growth of old fields.

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*Reserve estimates in some fields will decrease with time. Small fields are generally considered to be more susceptible than large fields to such reserve "shrinkage."

Industry opinion about the importance of "new gas from old fields" is quite varied. One reason for this variation of opinion is the anecdotal nature of much of the available evidence and the very mixed experiences of different companies. For example, one source reports claims of 40-percent increases in proved reserves with infill drilling,[42] while another, based on interviews with 14 major production and pipeline companies, reports that infill drilling has "not provided the large reserve additions needed to reverse the long-term decline in proved reserves," and that "relatively small reserve additions were believed to have been provided by extension of the economic life of pro-

Box E.—Sources of "New Gas From Old Fields"

- *Lowering of abandonment pressure.*—Wells are abandoned when operating and maintenance costs are not balanced by sufficient revenues from gas sales. Because gas-flow rates can generally be associated with wellhead pressures, an "abandonment pressure" can be specified for a given gas price. When gas prices rise, the abandonment pressure is lowered and total recovery efficiency of the reservoir is increased.
- *Infill drilling.*—The original premise of requirements for wide-well spacing was that gas reservoirs were sufficiently homogeneous so that very high-recovery efficiencies could be obtained with only a few wells, except in fields that had low permeability. More recently, it has been recognized that many reservoirs are heterogeneous in character and are compartmentalized, i.e., composed of relatively small, discontinuous interlaid pockets of gas-bearing rock. Drilling at higher density can intercept pockets that would otherwise not have been drained at traditional wide spacing.
- *Fracturing and acidizing.*—These well-stimulation technologies, which have wider application with increased gas prices, are used to speed gas flows and can add to resources by allowing completion of wells in low-permeability sands that otherwise would have been considered as "dry." They do this by allowing a higher recovery during the limited life of the well (at low-flow rates, the well may not last long enough to allow full recovery) and by opening up new "pay zones" too small to be economically developed by a new well.
- *Well workovers.*—Marginal wells may also be abandoned because of water encroachment, physical aging of well equipment, and accumulation of sand in the well bore. At higher gas prices, well workovers to correct these problems become possible.

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*However, the *rate* of recovery is extremely sensitive to these factors, as is the economic threshold of development for a field.

**This field is not considered a single field by all analysts, nor are its reserve levels completely agreed on. As noted previously, these are not uncommon problems, especially with large fields.

[41] Ibid.

[42] Personal communication, William Fisher, University of Texas at Austin, Feb. 9, 1982.

ducing reservoirs (by lowering abandonment pressures)."[43]

Unfortunately, it is difficult to translate this anecdotal evidence into credible estimates of past increases in recoverable resources available from this "new gas" effect. No collected set of data separates out this effect because the associated changes in reserve estimates are combined with the growth caused by normal development in the "revisions" and "extensions" data now published by EIA. Also, as discussed in chapter 5, the pace of "normal" development has quickened with rising prices and improved seismic technology, preventing any attempt to measure the effect as the difference between current and historical *rates* of field growth.

Attempts have been made to measure *future* growth of older fields that might be caused by higher prices. For example, a recent report has claimed that an increase in the price of "old gas"—gas controlled to prices well below market-clearing levels—could make an additional 52 TCF available: 27 TCF from lower abandonment pressures, 18 TCF from additional infill drilling, and 7 TCF from a combination of fracturing and other well-stimulation treatments, well workovers, and other measures.[44] This estimate is, to our knowledge, the highest of any released to date.

A major controversy surrounding this and other studies involves the extent to which the "additional" resources may already have been added to reserves or else may be developed at current prices (and, consequently, may already be a part of the "economic" portion of the recoverable resource base).

New Frontiers, Including Deep Areas.—Even though recent exploratory drilling in the frontier areas has had mixed success and several severe disappointments, considerable areas of untested or inadequately tested sedimentary rock remain that may hold considerable potential. Even extreme pessimists view areas such as the deepwater Gulf of Mexico, the Anadarko Basin, and the Western Overthrust Belt as having considerable potential. However, it is also inarguably true that areas such as the Gulf of Alaska, eastern Gulf of Mexico, the Southeast Georgia Embayment, and the Baltimore Canyon have been expensive failures[45] thus far. Unfortunately, it is not easy to document the opinions of the major oil companies—who traditionally are leaders in frontier exploration—because few details of their most recent resource assessments are available to the public. It is clear, however, that some of the majors, notably Exxon and Shell, are pessimistic about the overall Lower 48 potential and the Lower 48 onshore frontier areas. Given the speculative nature of these resources, the range of credible estimates of frontier undiscovered gas must be considered quite wide.

An important part of the controversy over the resource potential of frontier areas involves the economic viability of the potential resources rather than their physical presence. For example, much of the intense deep-drilling activity of the early 1980's in basins such as the Anadarko appears to have been a direct response to the very high prices for deep gas (as much as three times the market-clearing price) resulting from the price-controlled market. Prices for deep gas and other categories of gas entitled to special incentive pricing under NGPA have now dropped sharply, and drilling activity has dropped sharply as well. Consequently, some analysts question whether these expensive resources still belong in the economically recoverable resource base. Similar questions have arisen over some of the gas under the deep waters of the continental slope, now included in the USGS assessment and others.

The appropriate placement of these resources inside or outside of the recoverable resource base is complicated by several factors. First, uncertainty about the precise geologic conditions of these resources combined with the recent rapid fluctuations in drilling costs create substantial uncertainty about the cost of producing the resources using today's technology. Second, the present hesitancy of the industry to drill for these resources may not necessarily reflect the resources' lack of long-term economic viability but rather the current lack of gas demand and regulatory uncertainties about decontrol. Third, uncertainty is added by ambiguities in the common definitions of "recoverable resource base," some of which, e.g., allow the possibility of technological improvements that are in line with trends prevailing at the time of the assessment (this is USGS's boundary condition). This greatly complicates the evaluation of resources whose production may involve technological difficulties. Because of these factors, in OTA's opinion the boundary between economic and subeconomic, and consequently the magnitude of the recoverable resource base, is not well defined for the frontier resources.

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[43] Jensen Associates, Inc., "Early Effects of the Natural Gas Policy Act . . ., op. cit.

[44] C. S. Matthews, *Increase in United States "Old Gas" Reserves Due to Deregulation*, Shell Oil Co., April 1983.

[45] R. Nehring, "The Discovery of ...," op. cit.

Stratigraphic Traps.—Over the cycle of gas exploration, structural traps have tended to be the most favored drilling prospects. As possibilities for finding new large structures have declined, many explorers have shifted their strategy toward locating subtle stratigraphic traps, i.e., potential reservoirs whose main trapping mechanism is a gradation of the reservoir rock into layers of rock of low permeability laid down by the sedimentation process. Resource optimists expect to find large amounts of resources in these traps.

There are two major arguments against such expectations. First, there have been significant past efforts aimed at finding stratigraphic traps, especially in the Anadarko, Permian, Denver, and Powder River basins.[46] Second, it is argued: 1) that very large stratigraphic gasfields are unlikely to have remained undiscovered in the explored basins of the Lower 48 States because of the fields' large areal extent and the very high density of drilling in these basins, and 2) that most of the stratigraphic traps remaining to be discovered will be small. Nehring[47] also cites geologic arguments against the possibility of finding many large new stratigraphic traps, including the vulnerability of such traps to degradation or dissipation and Nehring's contention that the presence of multiple structural trapping possibilities in basins outside of the stable interior provinces makes it unlikely that many stratigraphic traps will exist outside of these provinces, the source of most past discoveries.

These are strong but not conclusive arguments. New efforts to locate stratigraphic traps can use seismic exploratory techniques not available to the earlier efforts. It is possible, though speculative, that several sizable traps that were "invisible" to earlier techniques could now be located. Similarly, arguments about drilling density are valid but must be tempered by the depth limitations of much of this earlier drilling and the clustering of such drilling around areas considered prospective by earlier standards.

Even if the arguments against finding large stratigraphic traps are correct, there remains significant uncertainty about the number of smaller fields that might exist and the actual potential for finding and exploiting these fields—the same uncertainty that affects assessment of the resource potential of small fields in general. Key factors affecting the potential for producing significant quantities of gas from these fields include gas prices and reductions in the costs of effective exploration techniques.

Conclusions

Based on the previous discussion, OTA accepts the possibility that discovery trends may have been sufficiently distorted by past regulatory and economic conditions and that sufficient resource possibilities exist in small fields, growth of old fields, and other sources to allow us to accept the estimates of PGC as *possible, but very optimistic*—a reasonable upper bound to the probable magnitude of the conventional gas resource base. On the other hand, we consider the extremely pessimistic estimate of Hubbert to be unlikely, and to a lesser extent we are also skeptical of the RAND estimate. Both come very close to the analogy of "running into a brick wall." Looking ahead to chapter 5, we can see that the Hubbert estimate implies a "conventional gas" production rate of about 3 or 4 TCF in 2000, an astoundingly low value. The RAND estimate implies that there will be at best only a handful of new exploration plays in the Lower 48, that these will be only moderate in size (2 to 10 TCF), and that there will be no really large "surprises" left; we believe this is possible, although quite pessimistic. However, the RAND assessment appears to have underestimated the potential for reserve growth in known fields, and it apparently has excluded some gas in low-permeability reservoirs that is currently economically recoverable. Therefore, we consider a credible lower bound to be somewhat higher than the RAND estimate.

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[46] Ibid.

[47] Ibid.

In conclusion, our best *guess*—and we chose this word carefully—is that a reasonable range for the magnitude of remaining conventional natural gas resources, *recoverable under technological and economic conditions not far-removed from today's,** is about *400 to 900 TCF* as of the end of 1982. This is not really a very wide range, given the basic uncertainty associated with resource assessment, but it *is* a wide range with respect to future production potential. The two ends of the range have very different implications about how difficult it is going to be to continue to replenish our current inventory of gas reserves over the next decade or two, and they have profound implications about what the role of natural gas in our energy economy will be in 2000. OTA believes that if the lower end is correct, reserve additions will fall off drastically within a few years, with production rates dropping in response. On the other hand, the upper range implies the potential for a very positive future for conventional gas production during this century. The next chapter explores these production issues in greater detail.

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*Including gas in low-permeability reservoirs that otherwise satisfies the conditions. This recognizes the ambiguous boundary between "conventional" and "unconventional" gas in such reservoirs.

Chapter 5

Gas Production Potential

Chapter 5

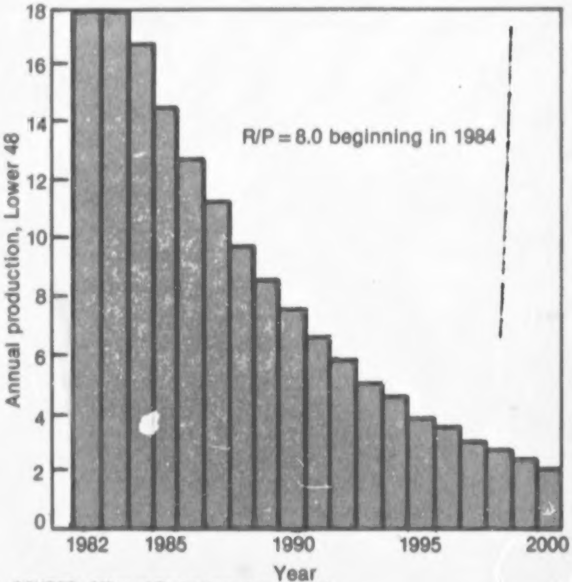
Gas Production Potential

There are a variety of alternative approaches to estimating the future gas production potential of the United States, including the use of complex computer programs using econometric, process engineering, or system dynamics approaches to model separately the gas exploration, development, and production processes. Although during the course of this study OTA examined several complex models in detail, we have chosen to use four relatively simple techniques to project future production potential. This approach reflects the high costs of using the complex models and some doubts we entertain about the expected accuracy of these models as forecasting tools. These doubts do not necessarily extend to the usefulness of the models as policy analysis tools; often, these models offer the valuable ability to test alternative policies under carefully controlled conditions. Some of the major natural gas supply models will be discussed in a background document to this technical memorandum.

Of the four approaches used by OTA to project the mid- to long-term (1990 and beyond) production potential for natural gas in the Lower 48 States, three focus specifically on the potential for continued additions to U.S. proved reserves. *The addition of new reserves to the U.S. gas system is the primary determinant of future gas availability.* The importance of new reserves can be illustrated quite simply by drawing the production that would likely result from the *failure* to add to reserve levels and reliance instead on current proved reserves as the *sole* "inventory" for production to draw on (see fig. 17). Assuming a constant reserves-to-production (R/P) ratio of 8.0, beginning in 1984, production would immediately begin to drop with shocking rapidity to about 2 trillion cubic feet (TCF) by the end of the century.*

Of the three approaches focusing on continued additions to U.S. proved reserves, the first projects future reserves by examining historical trends in all components of reserve additions (new field discoveries, extensions, new pool discoveries, and revisions), examining the underlying causes of the trends, and extrapolating into the future based on OTA's expectations of future conditions. In this extrapolation, we have drawn heavily on the insights gained in our examination of gas resource base assessments. The second approach projects only new field discoveries and then applies a "growth factor" to these discoveries based on historical experience with the growth of new fields and OTA's judgment about how the growth rate may have changed. The third approach is based on a geologist's* region-by-region examination of available gas resources and past exploratory success. In all three cases, production rates are

Figure 17.—Natural Gas Production From 1981 Lower 48 Proved Reserves



SOURCE: Office of Technology Assessment.

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*Conceivably, the initial reduction in production could be slowed by drilling additional development wells, effectively lowering the R/P ratio. The end result of this strategy would be, however, an even more rapid production collapse occurring a few years later than that shown in figure 17.

*Joseph P. Riva, Jr., Congressional Research Service.

calculated from reserve data by projecting future levels of the R/P ratio.

The fourth approach borrows a method used by M. King Hubbert in 1956,[1] tying future production directly to available resources by drawing freeform plots of the complete natural gas production cycle in such a manner that the cumulative production conforms to existing resource base estimates—in this case, to the estimates of Hubbert, the U.S. Geological Survey (USGS), and the Potential Gas Committee (PGC).

In each of the four approaches, ranges of production potential are estimated based on alternative assumptions about the magnitude of the resource base, efficiency of the exploratory process, and other factors.

OTA's use of four approaches, and alternative assumptions within the approaches, reflects our skepticism of our own and others' ability to project future gas production rates with any precision. A "most likely" or "best" projection was deliberately avoided because we believe that such a projection, beyond 5 years or so into the future, would be futile. Our purpose in this section is to illustrate the *plausible range* of possible future production rates and the general effects on production estimates of different interpretations of the causes of past trends and different assumptions about future conditions. The first approach is our slight favorite, but only because its level of disaggregation forces the analyst to deal more explicitly with the underlying causes of past events. This approach is discussed in the greatest detail.

At the end of the chapter, a variety of gas production forecasts by public agencies, private companies, and institutions are presented and discussed.

APPROACH NUMBER 1—PROJECTING TRENDS IN THE INDIVIDUAL COMPONENTS OF RESERVE ADDITIONS

The first approach separately projects trends in reserve additions from new field discoveries, new pool discoveries and extensions, and revisions.

New Field Discoveries

The discovery of gasfields represents the single most important force necessary for building a sustainable natural gas supply because a new gasfield not only adds to *current* reserves but also provides a source of considerably larger additions to future reserves through field growth after the discovery year. Reserve additions attributable to extensions and new pool discoveries and, to an extent, to revisions, are all, in fact, the inevitable consequence of previous new field discoveries. Therefore, if new field discovery rates increase or decrease, then at some point in the near future, reserve additions from extensions and new pool discoveries will almost certainly increase or decrease in a like manner.

Factors Affecting New Field Discoveries

The rate of annual additions to reserves from new field discoveries depends on a variety of factors, but most importantly on:

- *The undiscovered resource base.*—The physical nature of the resource base—including the amount of resources remaining to be found, the distribution of field sizes, the locations of fields, the distribution of types of geological traps (more or less difficult to pinpoint with available exploration techniques), and other physical attributes—is considered by some to be the single most important determinant of future new field discoveries.
- *Exploration technology.*—The rapid advance of exploration technology, e.g., computer-aided seismic technology, affects drilling success rates and, consequently, overall discovery rates. Also, technological improvements have opened up to commercial exploitation some areas whose complex geology had pre-

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[1] Described in M. K. Hubbert, "Techniques of Production as Applied to the Production of Oil and Gas," *Oil and Gas Supply Modeling*, S. I. Gass (ed.), National Bureau of Standards Special Publication 631, May 1982.

viously prevented acceptable success rates. Consequently, these improvements have expanded the recoverable resource base. Development of the Western Overthrust Belt is an important example of this effect.

- *Drilling and production technology.*—Improvements in production technology create an expanding recoverable resource base and, in turn, an increase in targets for the drill. For example, massive hydraulic fracturing technologies allow exploitation of fields in sands of low permeability that previously would have been subeconomic. Improvements in offshore drilling technology allow exploitation of gasfields in deeper and more hostile waters.
- *Current and perceived future gas prices and other economic variables.*—Such variables affect the propensity to drill and determine where to draw the line between a producible well and a dry hole. In some cases, the higher prices allow the use of well-stimulation techniques that would otherwise be too expensive,allowing successful production to be achieved from a well that would otherwise have had too low a flow rate. Additionally, the minimum acceptable reservoir size for production has grown smaller. The *relative* prices of gas and oil are important also because these will determine whether drilling will be preferentially aimed at targets where gas or oil are more likely to be found.
- *Schedules, financial terms, and other aspects of leasing.*—These also determine the number of attractive targets available for exploratory activity.
- *Industry willingness to take risks.*—All of the above factors and others play a role in determining the propensity of the exploration segment of the industry to assume the risks of wildcat drilling in unproved areas where much of the gas resource potential is thought to exist. Because this type of drilling often involves hostile environments and large capital requirements, much of this drilling is the domain of the major integrated oil companies and the large independents. Consequently, those factors that strongly affect the cash flow, capital availability, and economic incentives for this group of companies are particularly likely to affect the industry's propensity for risk-taking.
- *Historic prices and exploratory experience.*—There always exists an inventory of new field prospects known to explorers through past exploratory activities but undrilled or (in the case of "dry holes") uncompleted because of economic conditions or the availability of more promising prospects elsewhere. The key determinants of the size and character of this inventory are past exploratory experience and price profiles. The nature of the inventory is, in turn, an important determinant of new field discovery rates in the short-term, especially during the period following a change in price levels or regulatory controls.

Historical Variation of New Field Discoveries

During the 14 years of American Gas Association (AGA) data availability,* the annual additions of new field discoveries in the Lower 48 States have remained fairly steady, if somewhat cyclic, varying between a high of 2.9 TCF and a low of 1.3 TCF. (See fig. 18, which also shows the Energy Information Administration (EIA) data for 1977 to 1981.) Since 1967, the last year in which AGA estimated that total reserve additions exceeded production, the average of new field discoveries has been 2.0 TCF. Similarly, nonassociated new field discoveries have been equally steady, with a 14-year average of 1.7 TCF. Consequently, new field discoveries played a surprisingly small direct role in annual reserve additions during this period;** they averaged less than 20 percent of all annual additions from new discoveries and extensions and never exceeded 25 percent in any year.

Although the reserve additions reported as new field discoveries remained steady during this period, the size distribution of the fields discovered did not. As shown earlier in table 12, the average size of new gasfields became considerably smaller (reported year-of-discovery reserves of

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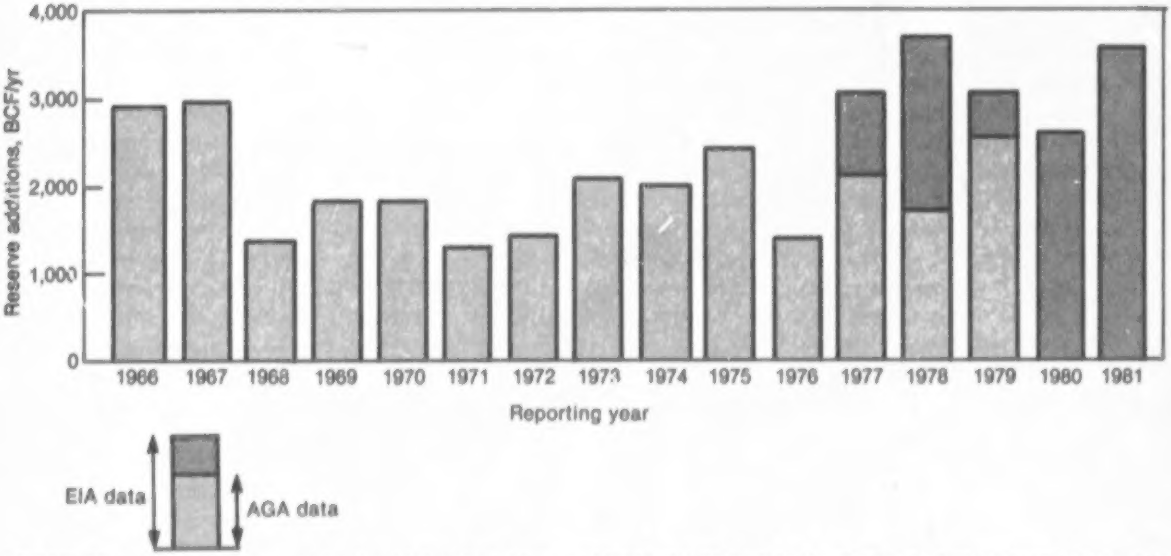
*Actually, AGA has compiled reserve additions data since 1947, but only began separately estimating new field discoveries in 1967.

**Clearly they did not play a small *indirect role* since many of the new pool discoveries and extensions in this period represented development of the fields discovered earlier in the period.

Figure 18.—Additions to Lower 48 Natural Gas Proved Reserves: New Field Wildcat Discoveries, 1966-81 (BCF)



SOURCES: Office of Technology Assessment, based on data from Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves—1981 Annual Report*, DOE/EIA-0216 (81), August 1982, and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, vol. 34, June 1980.

1.85 billion cubic feet (BCF) per successful new field wildcat in 1979 v. 18.56 BCF per successful new field wildcat in 1966). Furthermore, the lower average did not imply only a reduction in discoveries of giant fields; although this did occur, another change involved a very large increase in the number of very small class E fields* brought into production.

Because of the smaller size of newly discovered fields, a steady expansion of successful exploratory wells was required just to maintain the rather low annual discovery rate of the period. For example, completions of new field (gas) wildcats in the onshore Lower 48 increased from 126 in 1968 to 671 in 1979. Because of the substantial improvements in success rates (see fig. 13) for all new field wildcat drilling (from 8.5 percent in 1968 to 19.0 percent in 1980), however, actual drilling rates did not have to increase in proportion to the rate of completion. From a low of 4,463 wildcat wells in 1971, drilling reached 6,413 wells in 1979 and 8,052 in 1981.

The more recent (1977 to 1981) EIA new field discovery data (fig. 18) show considerable year-to-year variation with no apparent trend and are made even more difficult to interpret because of the break with the AGA data series. However, the EIA estimates of new field discoveries were higher during 4 of the 5 years of record than *any* AGA-recorded discovery rate from 1966 to 1979. Of interest is the source of these discoveries. Although areas like the Western Overthrust Belt and deep Anadarko Basin have been in the forefront of media coverage, most new field discoveries continued to come from more traditional gas-producing areas—onshore and offshore (Gulf of Mexico) Louisiana and Texas. For example, during both 1980 and 1981 these two States provided two-thirds of the total magnitude of reserve additions from new field discoveries in the Lower 48.[2]

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*Class E fields contain less than 6 billion cubic feet of recoverable gas.

[2] U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1980 and 1981, EIA Annual Reports, DOE/EIA-0216 80 and 81, October 1981 and August 1982.

Implications

The following key issues pertaining to new field discoveries remain essentially unresolved:

- Can the 1968-79 trend in new field discoveries—essentially a steady cycling around an average of 2 TCF/yr or so—be continued well into the future? If optimists about the gas resource potential of small fields are correct, a continuing strong exploratory drilling effort should be able to maintain this level for a number of years. If the pessimists about small fields—and about the remaining resource base in general—are correct, reserve additions from new field discoveries might drop within a few years.
- Do the higher EIA estimates of 1977-81 new field discoveries represent an actual increase, or are they the result of the change in reporting methodology? Does the EIA methodology place more of a newly discovered field's *ultimate* reserves into the first-year reserve estimate, leaving less room for secondary (extension and new pool wildcat) discoveries? If the EIA values represent a true increase in new field discovery rates, the sustainability of a high rate (perhaps 3.5 TCF/yr) of new field discoveries would seem to depend either on the availability of new giant fields or on extremely high rates of exploratory drilling and the availability of massive numbers of small fields, supported by either or both strong price incentives and continued improvements in exploration technologies (especially in terms of lowering the cost of detailed geological surveys).

The comparison of the three overlapping years of EIA and AGA data in figure 18 is tantalizing because the difference between the two data sets is considerably smaller in 1979 than in 1977 and 1978, and the EIA methodology changed in 1979. Some analysts have chosen to use AGA data until either 1978 or 1979, and EIA data thereafter, assuming that the two series are essentially continuous. However, the coincidence between the 1979 EIA and AGA estimates for new field discoveries may be an accident; the two data sets differ considerably for all of the other reserve addition categories in 1979.

The failure to resolve the above issues implies that a credible range for future new field discovery rates would be quite wide. Although defining the range is a matter for subjective judgment, OTA would put the range at about 1.5 to 3.5 TCF/yr for the next 10 to 15 years, *assuming that exploratory drilling remains active for the period.** The range for the next 2 or 3 years should be narrower, however, perhaps 2.0 to 3.5 or 2.5 to 3.5 TCF/yr. The reasoning for these judgments is as follows:

- The high end of the range for the immediate future is based on the distribution of new field sizes. Because the current high discovery rate has not depended on discovering giant fields—notoriously erratic occurrences—but on employing a very large number of exploration teams to discover many medium-sized and small fields, the physical ability of the system to maintain its recent new field discovery rates should logically be quite high unless the gas "bubble"—and the current slump in drilling and all other exploratory activity—continues.
- To obtain the lower end of the 10- to 15-year range, we assumed that the 1970's AGA data more accurately reflect the likely future and that continuing resource depletion will lead to poorer prospects and a slump from the average of 2.0 TCF/yr during that period. Also, it was assumed that the major reasons for the higher EIA values are methodological and do not reflect an *actual* increase over discovery rates reported by AGA. Consequently, the 1.5 TCF/yr reflects AGA conventions and probable followup field growth. The discovery levels actually *recorded* by EIA would be expected to be higher than this value, but the reserve growth caused by extensions and new pool tests would then be lower than would be predicted by pre-EIA historical experience.
- The higher end of the 10-year range assumes that the EIA data accurately reflect a major upward shift in the finding rate (volume of

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*Drilling is now in a substantial slump. The ranges of reserve additions discussed here would be unrealistically high if the current "bubble" in gas deliverability and the related difficulties in marketing new gas were to continue.

gas discovered per unit of exploratory activity). Additionally, it is assumed that continued improvements in exploration and production technologies allow further increases in finding rates and/or that exploratory drilling rates are increased. This end of the range is alined with a large resource base.

Extensions and New Pool Discoveries

As already noted, a new field is generally not sufficiently defined in its year of discovery to allow the "new field discoveries" portion of reported reserve additions to represent all or most of the actual recoverable resource in that field. In the years following discovery, additional exploratory wells are drilled to delineate the full extent of the resources present in the field. Wells that probe the boundaries of reservoirs or fields in order to establish their productive area are called extension wells or extension tests. Wells that search for additional reservoirs within already discovered fields are called new pool tests or new pool wildcats. The reserve additions from extension wells and new pool wildcats represent the results of a secondary or followup discovery process for new fields.

Factors That Affect Extensions and New Pool Discoveries

As with new field discoveries, the major determinants of extensions and new pool discoveries are the magnitude and nature of the "target" (in this case, not the undiscovered recoverable resource base, but only that portion of the remaining resource associated with discovered fields), the technology available to find the gas, and the nature of the incentives to drill:

- *The target.*—The "resource base" for extensions and new pool discoveries is the inventory of discovered but incompletely delineated fields. Limited data from the late 1960's and 1970's indicate that the major part of new field growth has occurred within the first 5 years after discovery. Consequently, unless incentives for gasfield development are lacking,* the magnitude of extensions and new pool discoveries should be strongly *and positively* tied to *recent* new field discoveries. Additionally, measures that increase current new field discoveries should soon lead to increases in extensions and new pool discoveries as the new fields are further developed.

  Aside from the total gas volume represented by the "target," that is, the inventory of discovered fields, the geological characteristics of the fields will also play an important role in determining future extensions and new pool discoveries. For example, older fields that were incompletely developed because a substantial portion of their in-ground resource was subeconomic* at the time of discovery are now good targets for new exploratory efforts. The size and complexity of newly discovered fields will partially determine the relationship between the initial year-of-discovery reported reserves and the later extensions and new pool discoveries that signify further development of the fields. Because the discovery wells of smaller, less complex fields can generally "prove" a high percentage of their total resource, these fields may offer less opportunity for this later development than was the case with the generally large, complex fields of earlier decades.
- *Technology.*—The same technological factors that affect new field discoveries affect extensions and new pool discoveries. Computer-assisted seismic technology is considered especially important in allowing extension wells and new pool tests to be drilled with high success rates. Fracturing technologies, by opening up previously uneconomic reservoir margins and tight reservoirs in already discovered fields, expand the target resource available.

  Advancements in exploratory technology have other, varied effects, however. For example, advanced seismic techniques, by offering a highly accurate picture of the potential of new fields shortly after discovery, may encourage a larger proportion of the ultimate recoverable gas to be drilled and "proved" in the initial year-of-discovery, leaving less room for followup discoveries. Advanced seismic techniques also may help compress the remaining field delineation into a shorter span of time, leading to increases over expected levels in extensions and new pool discoveries* for a few years after discovery of the field, followed by a later decrease in expected levels of these reserve additions.

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*The current gas "bubble" provides a disincentive for field development.

*Because of the small size or low permeability of the reservoirs or the low quality of the gas.

Historical Variation of Extensions and New Pool Discoveries

Figure 19 and table 16 illustrate the variation of extensions and new pool discoveries** in the Lower 48 States from 1966 to 1981. Extensions have consistently played the major role in total reserve additions. After declining in the mid to late 1960's, they remained stable around 6,000 BCF/yr from 1969 to 1976 and began to move upwards thereafter. As with the other categories of reserve additions, the shift to EIA data complicates an interpretation of the past few years. According to that data, however, extensions *by themselves* produced reserve additions of 10 TCF in 1981, equaling or surpassing *total* reserve additions in most years of the 1970's.

Some of the underlying causes of these trends may be understood by examining the trends in extensions of individual PGC reporting areas.[3] Extensions tend to be concentrated in only a few of

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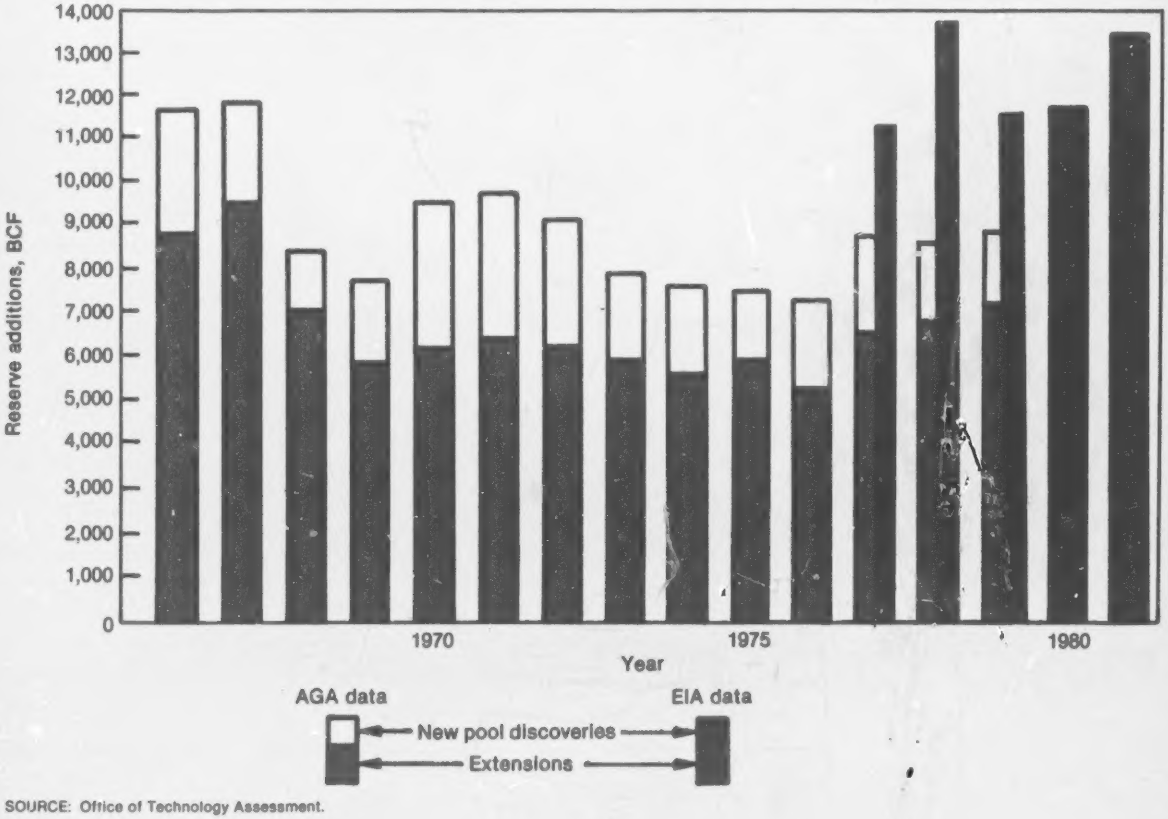
*That is, increases over the discovery rates projected by using historical data.

**As noted previously, new pool discoveries are reported as "new reservoir discoveries in old fields" in the AGA and EIA reserve reports.

[3] From R. Nehring, "Problems in Natural Gas Reserve, Drilling, and Discovery Data," contractor report to OTA, 1983.

Figure 19.—Additions to Lower 48 Natural Gas Proved Reserves: Extensions and New Pool Discoveries, 1966-81 (BCF)



SOURCE: Office of Technology Assessment.

Table 16.—Additions to Lower 48 Natural Gas Proved Reserves: Extensions and New Pool Discoveries 1966-81 (BCF)

Year	Extensions	New pool discoveries	Total
1966	8,767	3,110	11,877
1967	9,472	2,420	11,892
1968	7,037	1,426	8,463
1969	5,800	2,043	7,843
1970	6,146	3,363	9,509
1971	6,375	3,361	9,736
1972	6,154	3,096	9,250
1973	5,931	1,970	7,901
1974	5,693	1,952	7,645
1975	5,926	1,649	7,575
1976	5,337	1,994	7,331
1977	6,569 (8,056)[a]	2,144 (3,301)	8,713 (11,357)
1978	6,720 (9,582)	1,964 (4,277)	8,684 (13,859)
1979	7,112 (8,949)	1,690 (2,566)	8,802 (11,515)
1980	(9,046)	(2,577)	(11,623)
1981	(10,485)	(2,994)	(13,429)

[a] The values in parentheses are from EIA data; all other values are AGA reserve data.

SOURCE: Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves—1981 Annual Report*, DOE/EIA-0216 (81), August 1982; and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, vol. 34, June 1980.

these areas. Before 1968, field growth (primarily in relatively deep fields) in the Permian Basin provided a major fraction of total U.S. extensions—e.g., 43 percent in 1966. A sharp decline in Permian Basin reserve growth in 1968 was the primary reason for the general decline in extensions at the same time. The increase in extensions nationwide, beginning in 1977, resulted primarily from increases in:

- Western Overthrust Belt development;
- development of the deep Anadarko Basin;
- tight gas sand development in northeast Texas, Arkansas, and Louisiana; and
- Texas gulf coast development, including offshore fields, the South Texas Lobo Trend, and tight sands in the Austin Chalk.

Implications

Although the shift in data collection from AGA to EIA complicates interpretation, the sum of extensions and new pool discoveries has apparently been increasing from about 1976 to the present. In the AGA data, however, the increase only takes these "followup" discoveries back toward the levels achieved during the brief surge in new pool discoveries that occurred in the early 1970's. The EIA data show a considerably higher level of "followup" discoveries at about the levels that AGA estimated for 1966 and 1967.

In order to understand the recent variations in extensions and new pool discoveries, it is generally necessary to track the new field discoveries that serve as the "inventory" for the secondary exploration process. There is no obvious trend in the *national* new field discovery pattern (fig. 18) that would explain the recent higher level of secondary discoveries; AGA new field discovery data in the period immediately before this apparent surge in secondary discoveries show no similar increase. Consequently, in order to understand fully the causes of the recent surge, it probably is necessary to undertake a detailed examination of data at the level of individual fields. This is beyond the scope of OTA's study. However, some reasonable hypotheses can be fashioned based on the available data.

One possible explanation for the recent increases in extensions and new pool discoveries is that the increment over "normal" levels represents the delayed development of fields discovered earlier but not developed for economic reasons. The *dip* in new pool discoveries from about 1973-76 (fig. 19), which occurred despite an earlier period of steady new field discoveries that normally should have maintained steady levels of extensions and new pool discoveries, supports this explanation.

Some field-specific data also support a "delayed development" cause for part of the increases. For example, recent extensions in the Austin Chalk fields in southeast Texas appear to be tied to old fields that were marginally economic when discovered and had never undergone major development before recent price increases encouraged a reexamination. Because these fields were not "new," recent discoveries were probably recorded as extensions and new pool discoveries, even though there was little in the way of previously recorded new field discovery "inventory" to trace as the statistical cause of these secondary discoveries.

Similarly, another of the areas providing a substantial fraction of the increased extensions—the Western Overthrust Belt—probably also followed a delayed pattern of development. In this area, there was little incentive to delineate immediately the first new fields discovered because there was no means to transport the gas. Consequently, a substantial inventory of new fields could have built up until a point was reached where it became clear that the area contained sufficient reserves to justify a pipeline. Attaining this level of reserves would have introduced an incentive for field delineation, and secondary exploration would have then proceeded to cause a surge in extensions.

An additional cause of the recent higher recorded levels of secondary discoveries could be an acceleration in the pace of field-size delineation and development. Such an acceleration would result in the field size growth that in the past might have been spread out over a 60-year span being compressed into a shorter time period, with higher levels of annual reserve additions during this shorter period. Accelerated field size growth would be an expected consequence of higher gas prices, although the recent problems of reduced gas demand would tend to have the reverse effect, that of slowing down the pace of growth.

To summarize, two possible causes for recent increases in extensions and new pool discoveries are an accelerated field development pace and the delayed development of earlier new field discoveries whose development was (at least in part) initially uneconomic. If these are indeed the primary causes of the increases, this has important implications for future reserve additions. First, the faster pace of development means that *fewer* opportunities for field growth will be available in the later years of development; this should tend to decrease future reserve additions unless the rate of new field discoveries increases. Second, unless additional opportunities for growth from older fields are available, this source of "inventory" for extensions and new pool discoveries is unlikely to allow continuation of the currently high-reported levels of reserve additions. Although continuing technological advances and future gas price increases could offer some potential for sustaining reserve additions from older fields, the actual potential for reserve additions from this source is controversial.* In any case, most of any additional reserve growth from older fields seems likely to be attributed to infill drilling and other causes that will be reported as positive revisions rather than as extensions and new pool discoveries.

Recent and future discoveries of new fields still provide the primary source of inventory for future extensions and new pool discoveries. Consequently, future reserve additions from extensions and new pools depend heavily on the meaning of the sharply higher levels of *new field* discoveries reported during 4 of the past 5 years by EIA. As discussed in the "New Fields" section, OTA suspects that part of the reason why EIA's compilation of new field discoveries is substantially greater in magnitude than the levels shown by AGA is that the EIA data captures some of the reserves that AGA would have reported as second-year extensions, new pool discoveries, or positive revisions. If this is correct, the "growth factor" that should be applied to EIA's new field discovery data to account for field growth after the year of discovery will be smaller than the growth factor applicable to AGA data. For this reason, we do *not* believe that continuation of high levels of extensions and new pool discoveries is probable under current conditions.

Aside from the effects of the change in reporting, there are other reasons to believe that future levels of extensions and new pool discoveries may drop. First, much of the field growth in the past has come from the giant fields that took years to develop. A large percentage of recent new field discoveries, however, are small, class E (less than 6 BCF of recoverable gas) fields that will require little additional exploratory drilling past the initial wildcat. Second, the suspected acceleration in the pace of field development implies that some of the development that might in the past have taken place in the second year (and that would have been reported as extensions and new pool discoveries) now takes place in the first and will be reported as part of the "new field discoveries" reserve additions. Finally, the high-capital requirements for developing new fields in hostile environments—an increasing part of the remaining resource—demand a more thorough initial estimate of reserves, possibly leading to lower (statistical) growth later on.

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*As discussed in ch. 4, "New Gas From Old Fields."

To conclude, OTA does not believe it is likely that recent reserve additions from extensions and new pool discoveries of 12 to 14 TCF/yr will be sustained in the future even if the gas "bubble" ends and its negative effects on drilling cease. Instead, we project a range of 6 to 11 TCF/yr as an average over the next 10 to 15 years, except that for 1983-85 we project a range of 8 to 12 TCF/yr. The sole possibility of a higher long-term rate of reserve additions from this source lies with the discovery of several new, complex, super giant gasfields with large growth potentials; however, this possibility appears low.

Revisions

Revisions indicate changes in the volume of proved reserves that result from new information gained by drilling and production experience and corrections made to earlier estimates during the reporting year.

The AGA and DOE/EIA reporting of revisions is not identical because EIA has a separate category of "adjustments and corrections" that includes adjustments for changes in data samples, corrections of reporting errors, inclusion of late responses, and other factors. Theoretically, AGA's revisions should be equivalent to the sum of EIA's revisions, adjustments, and corrections. However, the data-gathering and analysis methods used by the two surveys are radically different, and their reserve and reserve addition estimates in the 3 years of overlap do not show good agreement. Consequently, they are not equivalent, although in displaying historical trends AGA revisions will be compared to EIA revisions plus adjustments and corrections.

Factors Affecting Revisions

Generally, revisions occur because of uncertainty associated with estimating the extent of the underground reservoir rock within a trap, the porosity and permeability of that rock, water saturation, pressure, and other physical reservoir characteristics that affect the cumulative volume of production over the life of the reservoir. Revisions tend to be a "catchall" category of reserve additions and deletions, and the many sources of revisions are difficult to separate out of the data. These sources include:

1. new knowledge gained by normal development drilling and production experience (e.g., changes in reservoir pressure-decline trends that indicate that earlier estimates were incorrect);
2. numerical errors in the original compilation of reserve estimates;
3. discoveries for which reporting had been delayed;
4. development drilling on a closer spacing that "discovers" new reserves;*
5. changes in production economics that lower or raise the abandonment pressure of a reservoir or that allow or prevent the use of well-stimulation techniques that increase recovery efficiency;
6. knowledge gained from extension tests that indicate a decrease in the estimated proved area of a reservoir or field (an *increase* would be recorded as an extension); and
7. miscellaneous statistical corrections and adjustments to the data.

Sources 2, 3, and 7 are considered "Adjustments and Corrections" by EIA and are reported separately.

Historical Variation of Revisions

From 1966 to 1981, net revisions were easily the most volatile of any of the four types of reserve additions. In the data reported by AGA for the contiguous 48 States, revisions varied from +6,256 BCF in 1967 to −3,546 BCF in 1973. In the EIA data for the same area, revisions plus adjustments and corrections varied from −2,911 BCF in 1977 to +4,346 BCF in 1981. Consequently, the year-to-year changes in revisions were the primary determinant of the year-to-year changes in gross reserve additions during the past 16 years. As shown in figure 20, a series of substantial posi-

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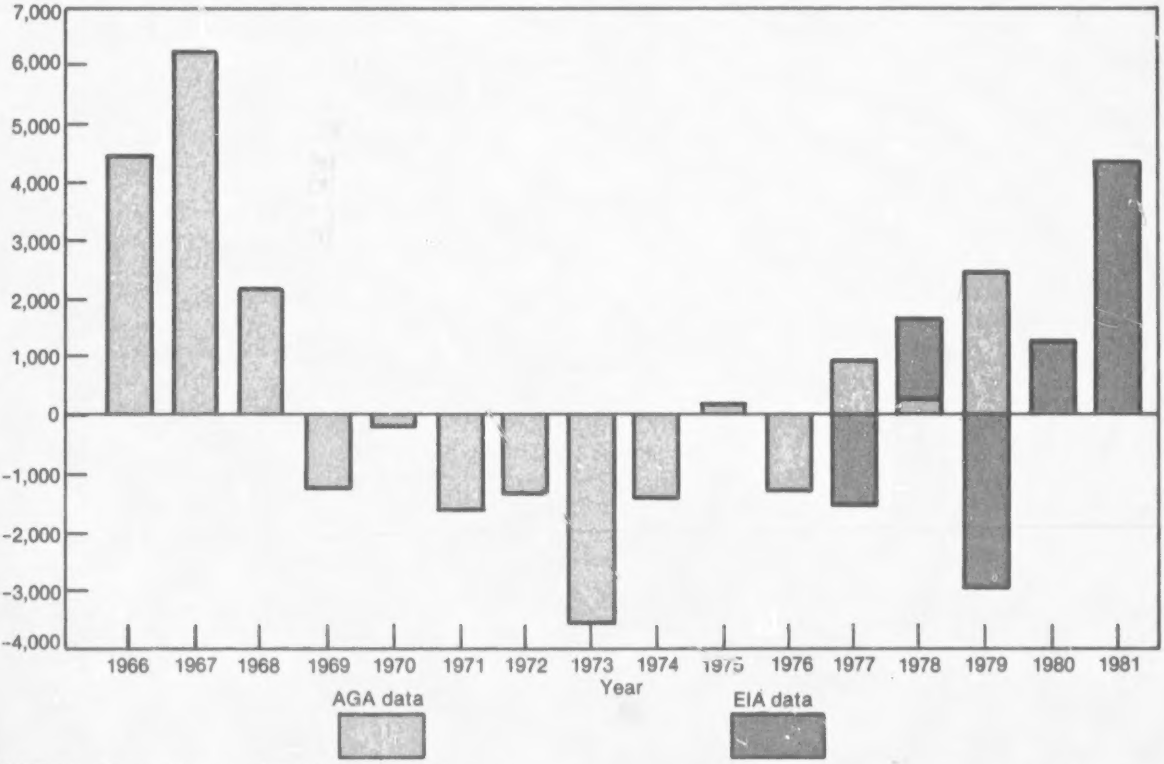
*New reserves "discovered" by a development well would be recorded as a revision if the gas is located in a pocket within the established boundaries of a reservoir yet is physically isolated from the reservoir's main drainage system and would not otherwise be produced.

Figure 20.--Additions to Lower 48 Natural Gas Proved Reserves: Revisions As Reported,[a] 1966-81 (BCF)



[a]NOTE: EIA plots for revisions + adjustments and corrections.

SOURCES: Office of Technology Assessment, based on data from Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves— 1981 Annual Report*, DOE/EIA-0216 (81), August 1982, and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, vol. 34, June 1980.

tive revisions in the mid-1960's changed to net negative revisions in almost every year in the 1970's, particularly in the onshore contiguous 48 States. As discussed later, understanding the role of these revisions is important in interpreting reserve changes during this period.

The largest negative revisions in the 1970's were reported in onshore south Louisiana and Texas Railroad Commission Districts 1, 2, 3, 4, and 6. Together, they contributed a total of over 30 TCF and proved to be remarkably persistent, continuing throughout the 1970's in both the AGA and EIA data. They were concentrated in older fields that had been producing for one to three decades before the revisions began.

The negative revisions in these six areas appear to be causally related to a situation that encouraged optimism in reserve calculations. During the 1930's, 1940's, and 1950's, exploration for natural gas in and adjacent to the gulf coast was highly successful. As a result, much more gas was discovered than could be produced, given the small size of the national natural gas market at the time. The transmission companies, having contracted for reserves with a productive capacity substantially exceeding what they could market, developed a system for prorating production among operators on a basis of remaining reserves (i.e., the larger an operator's reserves, the more gas the transmission companies would buy). This created a strong incentive for the operators to provide the most optimistic estimates of reserves they could justify. By 1970, following years of increasing production and gradual depletion, the operators were beginning to realize that reserves were overstated.

The size, timing, and geographic distribution of the reported negative revisions that followed depended primarily on when each major operating company recognized the problem and how they decided to revise their estimates downward, choosing to take them all at once or spreading them out over several years.[4]

Implications

An argument can be made that the historical record, erratic as it seems, supports the idea of generally positive revisions in the long-term. This is based on the view that the large but localized negative revisions of the 1970's appear to have ended. The trends in revisions for the areas *outside* the source area for the negative revisions seem far more positive.[5] For example, if the gulf coast revisions were subtracted from the total Lower 48 revisions, as shown in figure 21, the "amended revisions" would appear to support a projection of positive future revisions. On the other hand, an examination of the sources of revisions indicates that extreme caution should be used in forecasting the direction of future revisions.

Of the seven sources of revisions listed previously, the second and seventh are essentially random. The others either will always yield positive revisions, will always yield negative revisions, or may have a bias in one direction or the other. The first source, drilling and production experience, would be random if there were no incentives to be either pessimistic or optimistic in reserve

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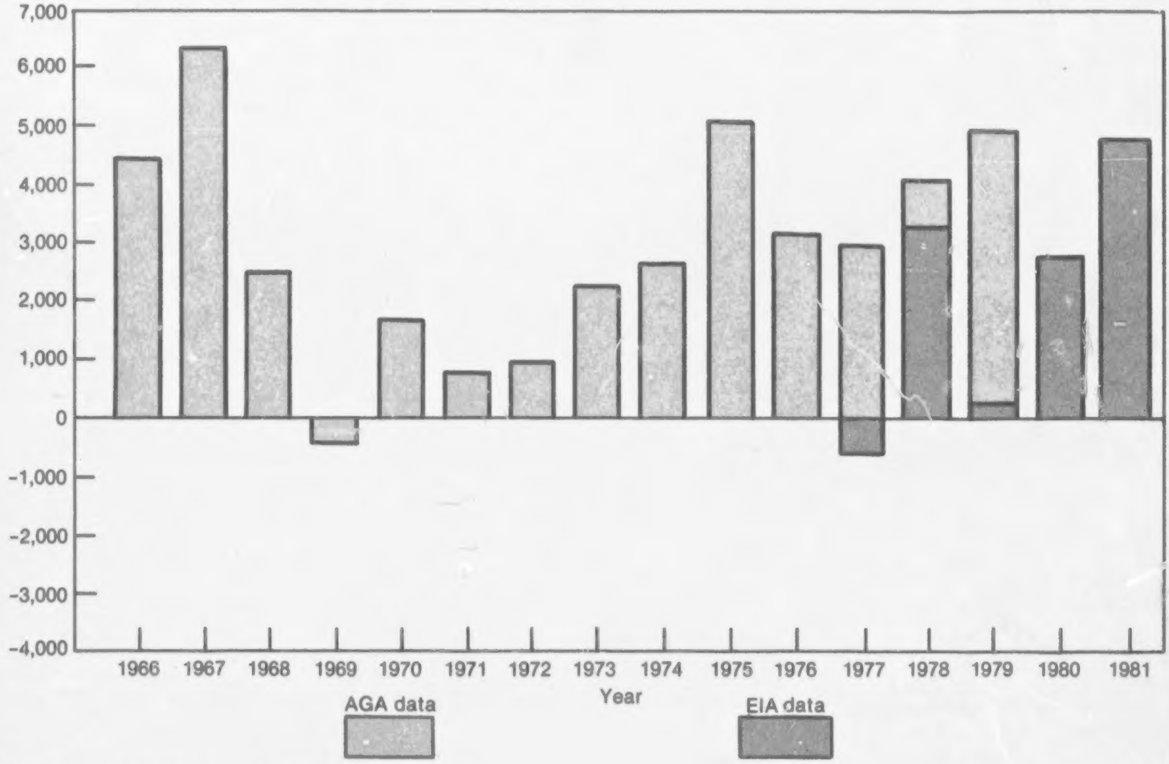
[4] Ibid.

[5] T. J. Woods, "On Natural Gas Trends," Gas Research Institute, 1982; R. Nehring, contractor report to OTA, op. cit.

Figure 21.—Additions to Lower 48 Natural Gas Proved Reserves: Revisions As Amended,[a] 1966-81 (BCF)



[a] NOTE: EIA plots are for revisions + adjustments and corrections.

SOURCE: Office of Technology Assessment.

calculations. However, the requirement to raise capital for field development or to meet minimum reserve requirements for a new pipeline are powerful incentives for optimistic reserve estimates. A tendency toward optimistic estimates would result in mostly negative revisions from drilling and production experience. The large negative revisions of the 1970's in the gulf coast and adjacent provinces appear to have resulted from just such a tendency.

The fifth source, changes in production economics, also could be random in that gas prices could rise faster (yielding positive revisions) or slower (negative revisions) than the costs of operating fields and enhancing production. Although rigid price controls or the competition of low-priced alternative fuels could conceivably lead to negative revisions from this source, it seems more likely that most such revisions would be positive, especially if gas becomes scarcer. In support of this argument, the growth in reserves attributed to well reworking, infill drilling, and lowered abandonment pressures—growth that would be reported as positive revisions—is seen by some analysts as an extremely important component of future reserve additions (see ch. 4, section on "New Gas From Old Fields").

Of the remaining sources of revisions, the third and fourth will always yield positive revisions, and the sixth always will yield negative revisions.*

The confusing mix of "positive," "negative," and "random" sources of revision make it extremely difficult to predict how revisions will behave in the future. Also, revisions data do not indicate which previous years' data are being revised. Consequently, it is difficult to know the causes of past revisions—a necessary prerequisite for intelligent forecasting. For these reasons, some analysts disregard revisions entirely in their trend analyses and implicitly assume they will not be a significant component of future reserve additions.

A reasonable range of average yearly revisions for the next 10 to 15 years appears to be 0 to 2 TCF/yr, with the positive tendency based on OTA's belief that there may be some significant potential from the growth of older fields due to lowered abandonment pressures, infill drilling, and the like.

Reserves-to-Production Ratio

Because the reserves-to-production ratio (R/P) measures the rate at which gas is produced from discovered reservoirs, it represents the analytical link between projections of new discoveries and forecasts of gas production.

Factors Affecting R/P

At the level of the individual production firm, the selection of a production rate—and, consequently, the selection of the R/P—represents an economic tradeoff between the cost of drilling additional wells and installing additional gas-gathering and processing facilities (i.e., the cost of increasing production), on the one hand, and the cost of holding reserves in the ground, on the other. Consequently, factors such as exploration and development costs, present and expected future gas prices, and interest rates all affect the R/P. For example, increases in current prices will theoretically lead to faster production, while expectations of real increases in future prices can cause production to be delayed.[6]

In oil production, it is well known that too fast a production rate—too low an R/P—can cause a premature decline in production and a loss of potentially recoverable reserves. For example, in a reservoir whose pressure is supplied mainly by water that displaces the oil as it is produced (a "water-drive" reservoir), an overly rapid rate of production can cause the encroaching water to flow around less-permeable sections of the reservoir, leaving behind the oil in these sections. When the water reaches the well, the added costs of water separation and disposal can cause premature abandonment.[7]

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*The sixth, knowledge gained from extension tests, yields only negative revisions because an *increase* in reserves caused by this source would be reported as an extension.

[6] Douglas Bohi and Michael Toman, "Understanding Nonrenewable Resource Supply Behavior," *Science*, vol. 219, Feb. 25, 1983.

[7] P. A. Stockil (ed.), *Our Industry Petroleum* (London: British Petroleum Co. Ltd., 1977).

Because gas flows more easily than oil, there is far more leeway in gas production, and production rates frequently can vary over a wide range. There are, however, the same kinds of physical limits to gas production as to oil production. Although some loss of ultimately recoverable gas from the well may be acceptable to the producer in exchange for a more rapid payback (from the higher flow rate), the potential for large losses will serve to limit flow rates.

Aside from the obvious economic factors and physical limitations to avoid resource loss, several other factors affect R/P:

- *Technology.*—The major technology affecting R/P may be rock-fracturing methods. The use of massive hydraulic fracturing and other fracturing techniques can open up low-permeability rock and cause marginal wells with low-flow rates to become rapid producers. The availability of sophisticated seismic exploratory techniques has reduced overall drilling costs—enhancing the incentive to drill additional wells to expand production—by increasing the success ratio; it also has helped improve the placement of successful wells to maximize production.
- *Geology.*—The rate of gas flow is directly dependent on the permeability of the gas reservoir formation and on its pressure and thickness. Although fracturing can partly compensate for low permeability, wells in tight gas formations generally produce much more slowly than do wells in more permeable rock because the fractures do not reach all of the tight reservoir rock. Similarly, gas in deep over-pressure formations will for short periods of time produce far more rapidly than in shallow, low-pressure formations;* in fact, the high pressures in such formations have caused severe technical problems in fields such as the Fletcher Field in southwestern Oklahoma, where wells and drilling equipment have been destroyed by failure to control the enormous pressures built up deep underground.[8] Also, field size distributions may affect R/P because smaller fields, which will be of increasing importance in future reserve additions, may be produced faster than large, complex fields.
- *Field Maturity.*—Early in a field's lifetime, R/Ps are typically very high because the major focus is on reserve delineation rather than development; during this period, pipeline and gas-processing capacity may be nonexistent or minimal and markets may be undeveloped. As pipeline capacity is added and sales contracts signed, the R/P will decrease rapidly. As the field tends toward depletion, the R/P may rise again as gas pressures drop and as drilling gravitates to the marginal, low-permeability formations. However because, the R/P will equal 1.0 in the last year of a field's production, the R/P will decrease during the very last years of the field.
- *Conservation Regulations.*—Some gas-producing States directly regulate production-related variables such as well spacing and flow rates. These regulations are intended to promote efficient development of reserves to prevent loss of ultimate recovery. Their origin lies in the disruption caused by the discovery of the east Texas field in 1930 and the large oversupply and resulting wasteful gas-production practices that followed.[9]
- *Market Demand.*—When the market is demand-limited (deliverability exceeds demand), as it is today, the R/P no longer provides a measure of gas-production capacity. Low demand can raise the R/P.
- *Reserve Requirements.*—The substantial capital requirements of gas transmission and distribution systems has led the transmission and distribution companies as well as Government regulatory agencies to pursue long-term contracts requiring high R/P's and high reserve requirements for pipeline approvals. These requirements do not apply, however, to mature areas where pipeline capacity is already in place.

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*However, once the "propping effect" of the gas under pressure is removed by partial production, the permeability of the reservoir may be reduced to "tight-gas" levels, and productions will slow.

[8] "Fletcher Area Underscores Perils in Deep Gas Reservoirs," *Oil and Gas Journal,* Feb. 7, 1983, p. 25.

[9] R. E. Megill, *An Introduction to Exploration Economics* (Tulsa, Okla.: Petroleum Publishing Company, 1971).

Historical Variation of R/P*

The early years of gas discovery in this country were marked by lack of a gas-distribution network, substantial discoveries of gas as a low-valued or even unwanted byproduct of oil exploration, and the eventual discovery of enormous reserves (e.g., the 1922 discovery of the giant Hugoton field in Kansas) that overwhelmed existing demand. The combination led to very high R/Ps in the 1920-40 period, followed by an era of continued decline.

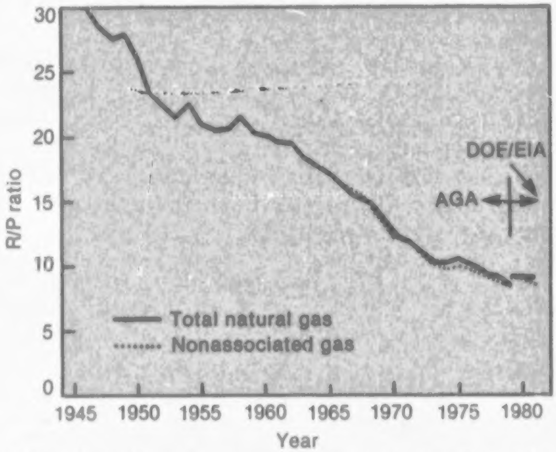
In the early years of the post-World War II growth, as new pipeline systems were constructed, previously unproductive proved reserves were developed. This activity increased the level of production without adding substantially to the volume of proved reserves, thus lowering the R/P. Later in the 1960's and 1970's, when the natural gas market had become supply constrained, production was again maintained by further development and a lowering of the R/P. At this time, however, the ability to obtain greater production from a given volume of proved reserves was improved by a geographical shift in production to the Gulf of Mexico and encouraged by economic changes that favored more rapid extraction rates.

The decline in R/P from 1946 to 1981 for the Lower 48 States is shown in figure 22. The AGA data cover the period 1946 through 1979, while DOE/EIA includes only the 5 years from 1977 through 1981.**

The AGA data show strong year-to-year declines in the R/P over virtually the entire 34-year period of available data. Recently, the rate of decline eased from an average of over 0.8 per year between 1966 and 1974, to an average of 0.5 per year during the 1975-79 period. DOE/EIA estimated dry gas data show a further easing of the decline rate to about 0.2 per year between 1977 and 1981.

Currently, the lowest R/P for the nonassociated gas of a major producing State is 6.6 in Louisiana.

Figure 22.—Reserve-to-Production Ratios for Natural Gas in the Lower 48 States



SOURCE: Office of Technology Assessment, based on data from Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves—1981 Annual Report*, DOE/EIA-0216 (81), August 1982, and American Petroleum Institute, American Gas Association, and Canadian Petroleum Association, *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, vol. 34, June 1980.

The lowest R/P for any geographical subdivision published by the 1981 DOE/EIA reserves report was a 4.0 for the State domain of the Texas offshore. The total Texas and Louisiana offshore, representing 33 percent of Lower 48 State production, stood at 6.5 in 1981. With the Gulf of Mexico excluded, the balance of the Lower 48 States had a 1981 R/P of 9.8. Contrasting strongly with the lower R/P's of the gulf coast would be that of 17.2 for the heavily depleted reservoirs of Kansas and 20.1 in Wyoming, where field development for newly discovered reserves was incomplete in 1981.

Implications

These examples of R/Ps for different areas of the United States during 1981 may indicate that the Lower 48 State R/P could move further downward in future years if gas supplies were found in areas with combinations of high-reservoir permeabilities and economics that favor extensive field development.* This is in fact what happened

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*Based on Jensen Associates, Inc., *Understanding Natural Gas Supply in the U.S.*, April 1983, contractor report to OTA.

**These displayed ratios are developed using the year-end reserves estimate for the year prior to the production period. This approach to calculating the R/P stems from a belief that production in a given year is more likely to be representative of reserves that are available at the beginning of the year.

*Some opinion exists, however, that some of the lower R/Ps are due to underreporting of reserves rather than to extremely rapid production. If true, this might indicate less potential for further lowering the national R/P.

throughout the 1970's as the Gulf of Mexico became an increasingly large component of the total supply. Between 1973 and 1981 the gulf's share of production grew from 20 to 33 percent.

An additional factor that might tend to push the R/P downwards is a continuation of current discovery trends towards smaller field sizes. It is widely believed that smaller fields will be delineated, developed, and produced over shorter periods of time than was historically the case with the mix of field sizes discovered until now.

On the other hand, some factors could cause the R/P to reverse and begin to climb upward. Future production trends may tend to increase the shares of gas from tighter, lower permeability reservoirs and other sources more expensive to develop, which could lead to slow rates of production from proved reserves. For example, both the deep Tuscaloosa trend and the Western Overthrust Belt are expected to have relatively high R/Ps; field development and gas-processing costs for these areas are too high to allow rapid depletion at current gas prices.[10] In addition, the R/P might tend to increase if future reserve additions were below annual production rates because the production capability (as a percentage of remaining reserves) of reservoirs tends to decline with their age,[*] and a rate of reserve additions that is below replacement levels will lead to an increasing average age for U.S. gas reservoirs.[11]

It is important to note that the balance between demand and supply will also play a critical role in determining the R/P. Because the purpose of this evaluation is to examine the potential for gas supply *if gas is highly sought after,* gas production—and, consequently R/P—is assumed to be based on a supply-limited situation.[**] This situation would tend to intensify the incentives to develop fields rapidly and to maximize production (minimize R/P). Rapid field development should not be expected, however, if the current gas "bubble" of oversupply continues. In this case, field development and production are likely to be slowed.

In conclusion, expected R/Ps in 15 to 20 years may range from values below today's levels—perhaps 7.0, or even somewhat lower—to levels slightly higher than today's—perhaps 9.5. Part of the future trend will be caused by the geologic nature of new discoveries and their geographic environment. These factors can be manipulated somewhat but are more likely to be imposed by the random success of future exploration. Because the R/P is also strongly affected by the willingness to drill development wells and to take other (expensive) production-enhancing measures, large increases in gas prices would tend to drive the R/P down to its lower limit. The lower value obviously can occur only with high gas demand, an assumption of this study. If gas demand were poor, the R/P could exceed 9.5 for a while. Eventually, however, the lack of exploration incentives would move proved reserves back into balance with production requirements.

Production Scenarios

Table 17 summarizes the ranges of reserve additions and R/P's projected for Lower 48 natural gas development. Tables 18 and 19 present production and reserves projections that represent the two extremes of the ranges in table 17. The first projection assumes an optimistic exploration future and rapid production of newly found reserves—predicated upon high gas prices, high demand, and an avoidance of large reserve additions in low-permeability areas that are hard to develop rapidly. The second projection assumes low finding rates and an increase in low-permeability reserves where production rates are limited. Because each projection represents a convergence of events of relatively low probability—e.g., the lowest rates of new field discoveries, extensions and new pool discoveries, zero revisions, and an upturn in R/P—the projections should be viewed as approximately bounding the range of production and proved reserve levels, rather than as identifying likely values.

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[10] E. F. Hardy and C. P. Neill, testimony to the Subcommittee on Fossil and Synthetic Fuels, Committee on Energy and Commerce, U.S. House of Representatives, June 1, 1981.

[*] Up to a point. During the last few years of a reservoir's life, its R/P must decrease because, in the last year, it will be 1.0. The last year's production will use up the entire remaining reserve.

[11] Ibid.

[**] That is, a situation where additional supplies at prevailing prices would be easily absorbed.

Table 17.—Summary of Projections of Components of Reserve Additions and R/Ps

New field discoveries	1983-85	2.0-3.5 TCF/yr
	1986-2000	1.5-3.5 TCF/yr
Extensions and new pool discoveries	1983-85	8.0-12 TCF/yr
	1986-2000	6.0-11 TCF/yr
Revisions	1983-2000	0-2.0 TCF/yr
R/P	2000	7.0-9.5
Scenario 1A: reserve additions	1983-85	17.5 TCF/yr
	1986-2000	16.5 TCF/yr
R/P	2000	7.0
Scenario 1B: reserve additions	1983-85	10.5 TCF/yr
	1986-2000	7.5 TCF/yr
R/P	2000	9.5

SOURCE: Office of Technology Assessment.

Table 18.—Lower 48 States Natural Gas Production and Reserves 1981-2000 (in TCF) SCENARIO 1A: Optimistic Exploration, Rapid Production

Year	Production	Reserve additions	Proved reserves	R/P[a]
1981 (actual)	18.5	21.5	168.6	9.0
1982 (approximate)	17.3	19.2[b]	170.7	9.75
1983	18.0	17.5	170.2	9.50
1984	18.9	17.5	168.8	9.0
1985	19.2	17.5	167.1	8.8
1986	19.4	16.5	164.2	8.6
1987	19.3	16.5	161.4	8.5
1988	19.5	16.5	158.4	8.3
1989	19.6	16.5	155.3	8.1
1990	19.4	16.5	152.4	8.0
1991	19.3	16.5	149.6	7.9
1992	19.2	16.5	146.9	7.8
1993	19.1	16.5	144.3	7.7
1994	19.0	16.5	141.8	7.6
1995	18.9	16.5	139.4	7.5
1996	18.8	16.5	137.1	7.4
1997	18.8	16.5	134.8	7.3
1998	18.7	16.5	132.6	7.2
1999	18.7	16.5	130.4	7.1
2000	18.6	16.5	128.3	7.0

Cumulative production after 1982 = 342.4 = 44% of USGS remaining resource.

[a] R/P calculated by dividing previous year's (yearend) reserves by production in the listed year.

[b] American Gas Association, "Preliminary Findings Concerning 1982 Natural Gas Reserves," *Energy Analysis*, Apr. 29, 1983.

SOURCE: Office of Technology Assessment.

Table 19.—Lower 48 States Natural Gas Production and Reserves 1981-2000 (in TCF) SCENARIO 1B: Pessimistic Exploration, Slowed Production

Year	Production	Reserve additions	Proved reserves	R/P[a]
1981 (actual)	18.5	21.5	168.6	9.0
1982 (approximate)	17.3	19.2[b]	170.7	9.75
1983	18.0	10.5	163.2	9.50
1984	18.1	10.5	155.6	9.3
1985	16.9	10.5	149.2	9.2
1986	16.4	7.5	140.3	9.1
1987	15.4	7.5	132.4	9.1
1988	14.6	7.5	125.3	9.1
1989	13.8	7.5	119.0	9.1
1990	12.9	7.5	113.6	9.2
1991	12.4	7.5	108.7	9.2
1992	11.8	7.5	104.4	9.2
1993	11.2	7.5	100.7	9.3
1994	10.8	7.5	97.4	9.3
1995	10.5	7.5	94.4	9.3
1996	10.0	7.5	91.9	9.4
1997	9.8	7.5	91.9	9.4
1998	9.5	7.5	87.6	9.4
1999	9.2	7.5	85.9	9.5
2000	9.0	7.5	84.4	9.5

Cumulative production after 1982 = 230 TCF = 30% of USGS remaining resource.

[a] R/P calculated by dividing previous year's (yearend) reserves by production in the listed year.

[b] American Gas Association, "Preliminary Findings Concerning 1982 Natural Gas Reserves," *Energy Analysis*, Apr. 29, 1983.

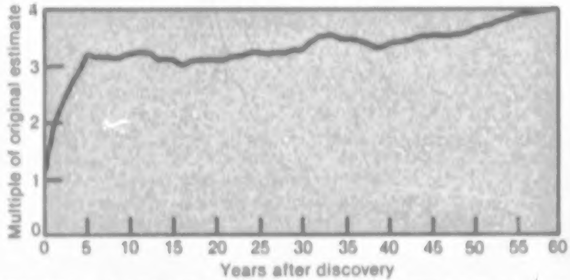
SOURCE: Office of Technology Assessment.

APPROACH NUMBER 2—PROJECTING NEW POOL DISCOVERIES, EXTENSIONS, AND REVISIONS AS A SINGLE GROWTH FACTOR

The preceding approach is designed to allow a projection of future gas reserves based on separate estimates of new field discoveries, extensions, new pool discoveries, and revisions. An alternative method is to project only new field discoveries and apply a "growth factor" to these discoveries that combines the effects of the other three categories of reserve additions.

USGS has used a field-growth approach to calculate the amount of gas remaining to be discovered in the inventory of identified fields.[12] In that application, a curve was constructed that describes the reserve growth in initial discoveries that occurs after the year of discovery, averaged over all discovered fields nationwide and over 9 of the 14 discovery years where appropriate data were available (1966-79). This curve, illustrated in figure 23, shows a 60-year growth in reserves to about four times the initial (discovery year) estimate of gas volumes discovered. The curve shows that most of this growth occurs in the first 5 years after the discovery year. In the USGS calculation, the curve was applied to the initial discoveries reported in *every* discovery year, assuming that reserve growth patterns of recently discovered fields would be the same as the patterns of much older discoveries. The gas volumes calculated in this manner—gas that is difficult to classify as

Figure 23.—The Growth of Year-of-Discovery Estimates of the Amount of Recoverable Natural Gas Discovered in the Lower 48 States



SOURCE: D. H. Root, "Estimation of Inferred Plus Indicated Reserves for the United States," app. F in *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.

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[12] U.S. Geological Survey Circular 860, app. F.

discovered or undiscovered—are called "inferred reserves" by USGS.

This method may be extended to project how the first-year estimates of reserve additions from future new field discoveries will grow in the years following the discovery year. However, certain adjustments have to be made. First, a growth factor calculated by tracking "initial discoveries" data must be increased if it is to apply directly to *new field* discovery data. This is because the discovery data[13] includes not only new field discoveries, but also "certain hydrocarbon accumulations which are significant from the standpoint that advances in exploration technology resulted in the discovery of such reservoirs."[14] Consequently, the year-of-discovery values are larger than those of "new field discoveries," and the later expansion is lower because some technology-based expansions are excluded. Adjusting the calculated growth factor to account only for growth of new fields may raise the factor by about 20 percent.[15]

Second, for the method to be credible, the assumption that the historical growth curve will continue to be valid must be relaxed somewhat. Many of the factors affecting the growth of recoverable reserves in newly discovered fields have changed; consequently, it appears likely that the growth curve has changed as well. The development of a credible forecasting procedure depends on defining a new curve or family of curves that logically fit these changed conditions.

Table 20 lists the arguments—some speculative—that support an increase or decrease (over historical levels of field growth) in the ultimate magnitude of reserve growth in new fields.[*]

USGS's estimate is not the only available estimate of field growth. Table 21 presents three other estimates, with ultimate growth ranging from 3.5 to 6.3 times the initial year-of-discovery estimate.

Table 20.—Arguments[a] for the Question, "Will the Reserve Growth in New Fields Be Larger or Smaller Than the Growth Recorded in Previously Discovered Fields?"

A. New fields will grow more

1. Recent increases in real gas prices are leading to greater recovery factors for gasfields—from closer spacing of development wells, extensions into less-permeable margins of reservoirs, exploitation of smaller pools, lowering of abandonment pressures, and reworking of older wells. Together, they increase the ultimate recovery (reported cumulative production at field abandonment).
2. The historical growth factor does not accurately reflect the actual field growth. The large negative revisions in onshore south Louisiana and Texas have artificially depressed reported field-growth rates. Because these revisions were due to a unique set of circumstances, they are unlikely to recur, and reported growth rates should increase.

B. New Fields Will Grow Less:

1. Part of the reason that the levels of new field discoveries reported by EIA were higher than those reported by AGA during the 3 years the two reports overlapped is probably that EIA reported reserve additions during the discovery year that AGA did not report until the second year. Therefore, when EIA-reported trends are used to project future new field discoveries, the growth factor used should be smaller than the historical average, which was derived from AGA data.
2. The historical growth factor was derived from data developed during a time when giant gasfields dominated gas reserves. Giant fields with multiple pools take many years to develop and are generally believed to have greater relative growth than small fields. Present and future field sizes will be smaller and should be expected to have smaller growth factors and faster development.
3. Improvements in seismic and other exploration technology, as well as in reservoir engineering, allow clearer initial delineation of field boundaries and other field characteristics and more accurate first-year reserve estimates. This should leave less room for growth.
4. Increased gas prices have led to acceleration of field development. Some of the development that might previously have taken place in the second year now takes place in the first year and is reported as part of the initial new field discovery reserve data.
5. High capital requirements to develop new fields in hostile environments—an increasing feature of today's resource base—require a more accurate first-year estimate of reserves, leading to lower "growth" later on.

[a] Some of these arguments are speculative. For example, in B.1., OTA has not determined the cause of the AGA/EIA differences in reported new field discoveries.

SOURCE: Office of Technology Assessment.

In order to use the "growth-factor" approach to project future gas production, Jensen Associates, Inc., an OTA contractor, constructed a simple model that applied growth curves similar to

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[13] The data came from table XIV of *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada*, vols. 21-34, 1966 through 1979, American Gas Association/American Petroleum Institute/Canadian Petroleum Association.

[14] Ibid.

[15] Robert Paszkiewicz, Jensen Associates, personal communication.

[*] These conditions are the same as those affecting revisions, extensions, and new pool discoveries.

Table 21.—Alternative Estimates of Growth Factors for Initial Reserve Estimates for Gasfields

Author	Suggested growth factors
1. USGS (Root) (1981) ..	4.0, all fields
2. Haun (1981)	4.0, fields younger than 48 years 5.0, fields older than 48 years
3. Hubbert (1974)	3.5, all fields
4. Marsh (1971)	5.0, fields younger than 28 years 6.3, fields older than 28 years

1. D. H. Root, "Estimation of Inferred Plus Indicated Reserves for the United States," app. F in G. L. Dolton, et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U.S. Geological Survey Circular 860, 1981.
2. J. D. Haun, "Future of Petroleum Exploration in the United States," *AAPG Bulletin* 656(10), 1981.
3. M. K. Hubbert, "U. S. Energy Resources, A Review as of 1972," S. Res. 45, ser. No. 93-40 (92-75), Committee on Interior and Insular Affairs, U. S. Senate, 1974, cited in Haun, ibid.
4. G. R. Marsh, "How Much Oil Are We Really Finding," *Oil and Gas Journal*, Apr. 5, 1971, cited in Haun, op. cit.

SOURCE: Office of Technology Assessment.

that in figure 23 to both known fields and to projected levels of new field discoveries. A growth curve that reached a factor of 4.0 in 60 years was applied to all pre-1982 discoveries, while curves with 30-year growth periods were applied to discoveries from 1982 on. The period of 30 years was selected to reflect OTA's belief that the pace of field development has quickened. The choice is a guess because data sufficient to calculate a new timetable are not available. The uncertainty in the ultimate value for the growth factor is reflected in a range of values from 3.0 to 5.0. In OTA's opinion, 5.0 represents an optimistic upper-bound on future growth in new fields.

Tables 22 through 24 present the results of three scenarios representing the search for reasonable upper- and lower-bounds on future gas production.* For each scenario, the "growth-curve" methodology was applied only to nonassociated gas. Associated gas was projected separately by applying a gas-to-oil production ratio of 1.3 MCF per barrel of crude oil to the EIA's 1981 oil production forecast.[16]

Table 22.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 2A: Very Optimistic[a]

Year	Total gas production	Nonassociated gas Production	Nonassociated gas Reserve additions	Nonassociated gas Proved reserve	Nonassociated gas R/P	Assoc./dissolved gas[b] production
1982	18.7	15.7	10.2	132.8	8.8	3.0
1983	18.2	15.3	11.7	129.2	8.7	2.9
1984	18.0	15.2	13.0	127.0	8.5	2.9
1985	18.0	15.2	14.8	126.6	8.3	2.8
1986	18.3	15.5	15.5	126.7	8.2	2.8
1987	18.6	15.8	15.8	126.6	8.0	2.7
1988	18.9	16.2	15.9	126.3	7.8	2.7
1989	19.3	16.5	16.0	125.7	7.6	2.7
1990	19.5	16.8	16.0	124.9	7.5	2.7
1991	19.7	17.1	16.1	123.9	7.3	2.6
1992	19.8	17.3	16.2	122.8	7.2	2.6
1993	19.8	17.3	16.2	121.7	7.1	2.5
1994	19.7	17.2	16.3	120.8	7.1	2.5
1995	19.6	17.2	15.3	119.0	7.0	2.4
1996	19.3	16.9	15.4	117.4	7.0	2.4
1997	19.1	16.8	15.4	116.0	7.0	2.4
1998	19.0	16.6	15.4	114.8	7.0	2.3
1999	18.8	16.5	15.5	113.8	7.0	2.3
2000	18.7	16.4	15.5	112.9	6.9	2.3

Cumulative production after 1982 = 342.4 TCF = 44% USGS remaining resource.

Note: Rows and columns may not add exactly due to rounding.

[a] Assumptions: Nonassociated gas new field discovery rate = 3,000 BCF/yr
Growth factor = 5.0
Additional growth from price rises for old gas = 1000 BCF/yr from 1985 to 1995.

[b] Associated/dissolved gas—gas found in the same reservoir with oil.

SOURCE: Jensen Associates, Inc., contract submission to the Office of Technology Assessment, 1983.

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*The production projections in the three tables should be viewed as slightly pessimistic. This is because they are based on projected 1982 nonassociated reserve additions of 8.7-10.2 TCF, whereas preliminary reports (based on the annual reports of the major oil and gas companies) indicate that actual 1982 additions may have been significantly higher, perhaps as high as 15 or 16 TCF.

[16] U.S. Department of Energy, *1981 Annual Report to Congress*, vol. 3, p. 62.

Table 23.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 2B: Pessimistic[a]

Year	Total gas production	Nonassociated gas				Assoc./dissolved gas[b] production
		Production	Reserve additions	Proved reserve	R/P	
1982	18.7	15.7	8.7	131.3	8.8	3.0
1983	18.0	15.1	8.4	124.6	8.7	2.9
1984	17.4	14.6	8.3	118.4	8.5	3.0
1985	16.9	14.1	8.3	112.6	8.4	2.8
1986	16.4	13.6	8.2	107.2	8.3	2.8
1987	15.9	13.2	7.6	101.7	8.1	2.7
1988	15.4	12.7	7.6	96.6	8.0	2.7
1989	15.0	12.3	7.7	92.0	7.9	2.7
1990	14.6	11.9	7.7	87.7	7.7	2.7
1991	14.2	11.6	7.7	83.8	7.6	2.6
1992	13.8	11.2	7.7	80.3	7.5	2.6
1993	13.4	10.9	7.7	77.1	7.4	2.5
1994	13.0	10.5	7.7	74.4	7.3	2.5
1995	12.6	10.2	7.2	71.4	7.3	2.4
1996	12.2	9.8	7.2	68.8	7.3	2.4
1997	11.8	9.5	7.1	66.5	7.3	2.4
1998	11.5	9.2	7.1	64.4	7.2	2.3
1999	11.2	8.9	7.1	62.6	7.2	2.3
2000	11.0	8.7	7.1	61.0	7.2	2.3

Cumulative production after 1982 = 254 TCF = 33% USGS remaining resource.

Note: Rows and columns may not add exactly due to rounding.

[a] Assumptions: Nonassociated gas new field discovery rate = 1,500 BCF/yr
Growth factor = 4.0
Additional growth from price rises for old gas = 500 BCF/yr from 1985 to 1995.

[b] Associated/dissolved gas—gas found in the same reservoir with oil.

SOURCE: Jensen Associates, Inc., contract submission to the Office of Technology Assessment, 1983.

Table 24.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 2C: Very Pessimistic[a]

Year	Total gas production	Nonassociated gas				Assoc./dissolved gas[b] production
		Production	Reserve additions	Proved reserve	R/P	
1982	18.5	15.5	8.7	131.3	8.9	3.0
1983	17.7	14.8	8.0	124.7	8.9	2.9
1984	16.9	14.0	7.5	118.1	8.9	2.9
1985	16.1	13.3	6.4	111.2	8.9	2.8
1986	15.3	12.5	6.1	104.9	8.9	2.8
1987	14.5	11.8	5.4	98.5	8.9	2.7
1988	13.8	11.1	5.4	92.8	8.9	2.7
1989	13.1	10.4	5.4	87.9	8.9	2.7
1990	12.5	9.9	5.5	84.4	8.9	2.7
1991	12.0	9.4	5.5	79.6	8.9	2.6
1992	11.5	8.9	5.5	76.1	8.9	2.6
1993	11.1	8.6	5.5	73.1	8.9	2.5
1994	10.7	8.2	5.6	70.5	8.9	2.5
1995	10.4	7.9	5.6	68.1	8.9	2.4
1996	10.1	7.7	5.5	66.0	8.9	2.4
1997	9.8	7.4	5.5	64.1	8.9	2.4
1998	9.5	7.2	5.5	62.4	8.9	2.3
1999	9.3	7.0	5.5	60.9	8.9	2.3
2000	9.1	6.8	5.5	59.6	8.9	2.3

Cumulative production after 1982 = 223.4 TCF = 29% USGS remaining resource.

Note: Rows and columns may not add exactly due to rounding.

[a] Assumptions: Nonassociated gas new field discovery rate = 1,500 BCF/yr
Growth factor = 3.0
No additional growth from price rises for old gas

[b] Associated/dissolved gas—gas found in the same reservoir with oil.

SOURCE: Jensen Associates, Inc., contract submission to the Office of Technology Assessment, 1983.

APPROACH NUMBER 3—REGION-BY-REGION REVIEW OF RESOURCES AND EXPLORATORY SUCCESS*

Using a region-by-region review to project future gas production involves a geologist's examination of a variety of factors affecting production in 10 individual regions of the Lower 48 States and his subjective evaluation of their future production potential.

For this approach, the gas resource base was assumed to be a compromise between the assessments of USGS and PGC. For each region, a resource value was selected by examining the field size and number implications of the two assessments and choosing the value that seemed more realistic. Then, future additions to proved reserves were estimated, based on a subjective evaluation of the following factors:

- *Difficulty and expense of development.*—Based on expected field sizes, depths, known geology.
- *Announced leasing schedules.*
- *"Maturity" of province.*—The percent of total expected resources that have already been developed.
- *Recent development history.*—Especially, the rates of entry into proved reserves of the remaining resources.

For each region, it was generally considered unlikely that a very high percentage of the remaining undiscovered resource—say, 50 percent or greater—could be transferred into proved reserves by 2000, and this situation acted as a strict limit on production in some regions, for example, in the "west Texas and eastern New Mexico" region.**

Tables 25 and 26 present two scenarios of future gas production and reserve additions based on the above approach. Scenario 3A projects that one-

Table 25.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 3A

Year	Production	Reserve additions	Proved reserves	R/P
1981	18.5	21.6	168.6	9
1982	18.6	10.9	160.9	9
1983	17.6	10.9	154.2	9
1984	16.8	11.2	148.5	9
1985	16.1	11.2	143.5	9
1986	15.7	11.2	139.0	9
1987	15.3	11.2	135.0	9
1988	15.1	11.2	131.0	9
1989	14.7	11.2	127.4	9
1990	14.5	11.2	124.1	9
1991	14.3	11.2	121.0	8
1992	14.2	11.2	118.0	8
1993	14.0	11.2	115.2	8
1994	13.7	10.1	111.6	8
1995	13.5	10.1	108.2	8
1996	13.4	10.3	105.1	8
1997	13.3	10.3	102.1	8
1998	13.0	10.3	99.4	8
1999	12.8	10.3	97.0	8
2000	12.6	10.3	94.6	8

Cumulative production after 1982 = 260.6 = 34% USGS remaining resource.

SOURCE: J. P. Riva, Jr., *A Projection of Conventional Natural Gas Production in the Lower 48 States to the Year 2000*, Congressional Research Service/Library of Congress, June 10, 1983.

Table 26.—Lower 48 States Natural Gas Production and Reserves, 1982-2000 (in TCF)—Scenario 3B

Year	Production	Reserve additions	Proved reserves	R/P
1981	18.5	21.6	168.6	9
1982	18.7	12.1	161.9	9
1983	18.0	12.1	156.0	9
1984	17.3	12.1	150.8	9
1985	16.8	12.1	146.1	9
1986	16.2	12.1	142.0	9
1987	15.8	12.1	138.3	9
1988	15.4	12.1	135.0	9
1989	15.0	12.1	132.1	9
1990	15.1	12.1	129.1	8.5
1991	15.6	12.1	125.5	8
1992	15.7	12.1	121.9	8
1993	15.2	12.1	118.8	8
1994	14.8	12.1	116.0	8
1995	14.5	12.1	113.6	8
1996	14.2	12.1	111.5	8
1997	13.9	12.1	109.7	8
1998	13.7	12.1	108.0	8
1999	13.5	12.1	106.6	8
2000	13.3	12.1	105.4	8

Cumulative production after 1982 = 274 = 35% USGS remaining resource.

SOURCE: J. P. Riva, Jr., *A Projection of Conventional Natural Gas Production in the Lower 48 States to the Year 2000*, Congressional Research Service/Library of Congress, June 10, 1983.

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*The analysis described in this section was performed by Joseph P. Riva, Jr., Specialist in Earth Sciences, Congressional Research Service (CRS). Riva's full report, which is part of CRS's participation in this study, will be incorporated in a background document to this technical memorandum.

**To stabilize current gas production to the end of the century in this region, 96 percent of the estimated undiscovered gas in the region would have to be discovered by 2000. From 1970 to 1981, 23 percent of the inferred reserves plus undiscovered resources were added to reserves.

quarter of the gas estimated to be available in undiscovered fields at the end of 1981 will be discovered by 2000. This compares to 55 percent of the undiscovered gas being discovered between 1945 and 1981, a period when larger prospects were available, but also when gas discovery rates may have been hampered by low regulated prices. In this scenario, gas production is projected to increase in the Rocky Mountains and Great Plains region, the Eastern Interior region, and the Appalachian region; in addition; production begins in Oregon-Washington and on the Atlantic continental shelf. However, major production decreases are projected for west Texas and eastern New Mexico, the midcontinent, and the gulf coast, all critical gas producers today.

Scenario 3B assumes that exploration becomes more efficient and that 35 percent of the resources in undiscovered fields can be discovered by 2000. Even under this more optimistic scenario, however, gas production will decline to 13.3 TCF by 2000.

APPROACH NUMBER 4—GRAPHING THE COMPLETE PRODUCTION CYCLE

Projecting future gas production by graphing the complete production cycle is based on the expectation of M. King Hubbert that the complete cycle of production will somewhat resemble a bell-shaped curve and that knowing the area under the curve—the total recoverable resource—allows a reasonable facsimile of the entire curve to be drawn, once about a third or more of the production cycle has been completed. Hubbert used this approach in 1956[17] to show that then-current estimates of the remaining oil resource base implied that oil production was on the verge of peaking and then declining.

In this application, gas production values for 1900-82 were plotted, and three freeform curves were extended from the 1982 production rate such that the area under the curves equalled the remaining gas resources estimated by, respectively, Hubbert, USGS, and PGC (see table 5). These curves are shown in figure 24.

The curves show that Hubbert's assessment implies an extraordinarily sharp decline in production, so that by 2000 the total Lower 48 production rate would be about 3 TCF. Since there is little flexibility in drawing this curve, it appears unlikely that the range of uncertainty due to the selection of the curve's shape is greater than about 2 to 5 TCF in 2000.

The curves representing the USGS and PGC gas resource assessments were drawn so that the declining portion of the curve resembles a mirror image of the ascending portion. Both curves show production rates staying steady at least until 2000. A plausible physical interpretation of the curves is that they represent a resource base that still retains a substantial number of large fields amenable to rapid rates of production. Furthermore, the shape of the curves is clearly alined with high demand for gas and prices that encourage substantial development drilling as well as vigorous exploratory efforts.

The USGS and PGC curves obviously can be redrawn to reflect different conceptions of how the production cycle might unfold. However, the necessity of maintaining existing production trends in the early years and of tapering-off gradually as the resource is depleted limits the options. Figure 25 shows the original USGS curve and a second curve that reflects a different conception, that of a production decline that commences earlier but proceeds at a more gradual rate. This second curve might reflect a future where industrial demand for gas declines and exploratory activity and development drilling proceed at a lower level. It might also reflect a resource base whose fields are smaller, in more difficult to develop locations, and of lower average permeability.

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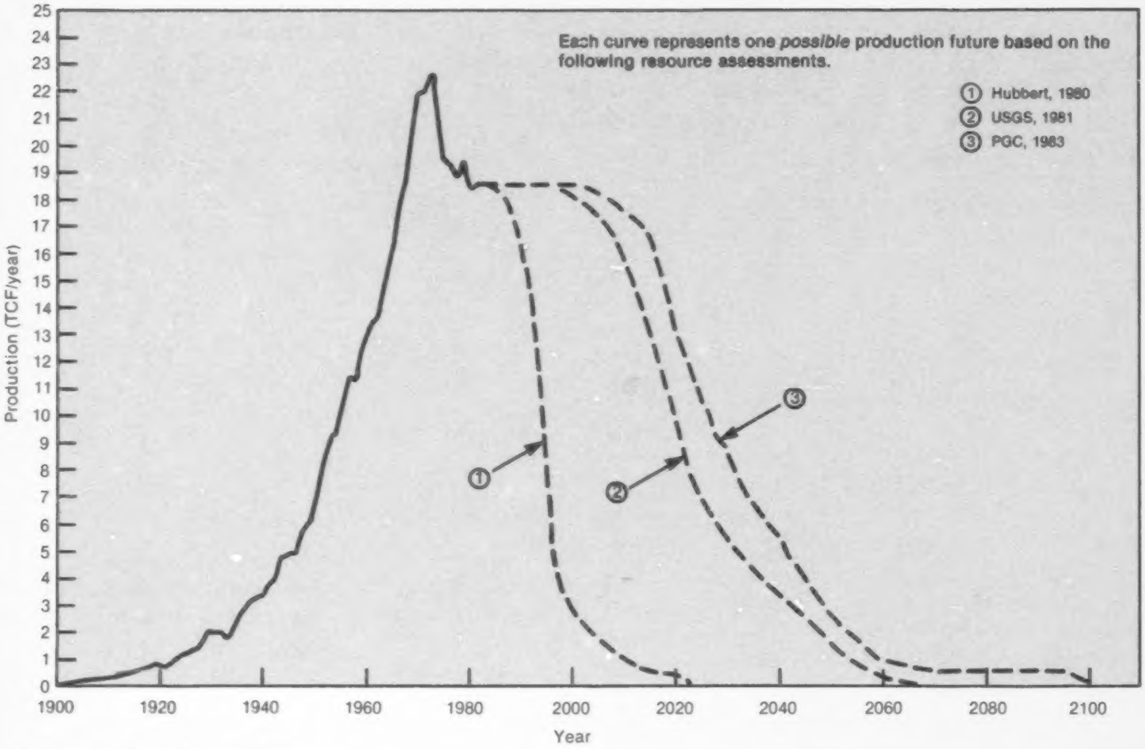
[17] M. K. Hubbert, "Nuclear Energy and Fossil Fuels," in American Petroleum Institute, *Drilling and Production Practice* (1956), cited in M. K. Hubbert, "Techniques of Prediction as Applied to the Production of Oil and Gas," *Oil and Gas Supply Modeling*, S. I. Gass (ed.), National Bureau of Standards Special Report 631, May 1982.

Figure 24.—Future Production Curves for Conventional Natural Gas in the Lower 48 States



SOURCE: Office of Technology Assessment.

A RANGE FOR FUTURE GAS PRODUCTION

In comparing figures 24 and 25 to the production projections produced by the alternative methods, some interesting conclusions can be drawn. *First, the higher end of the production ranges, which shows essentially stable production levels out to 2000, appears to be quite compatible with the USGS and PGC curves,* as drawn in figure 24. It should be remembered, however, that there are interpretations of the detailed physical nature of the gas resource base that, while compatible with the *overall magnitude* and even the regional estimates of USGS or PGC, could be completely *incompatible* with the high year 2000 production projection. The second curve in figure 25 displays such an alternative interpretation, and there are more radical possibilities as well.*

A second conclusion is that the lower end of the production range—about 9 TCF by 2000—is really much too optimistic for a believer of the Hubbert or RAND resource estimate. This is because the assumptions of the lower end of the range, while appearing to be pessimistic to a "resource optimist," may actually appear somewhat optimistic to a "resource pessimist." This end of the range assumes that the fairly low new field discovery rates of the early 1970's are more realistic as a long-term average than are the higher rates of the last few years, *but it ignores the possibility that even these low rates might go down still farther as resource depletion continues.* Consequently, the true production implication of

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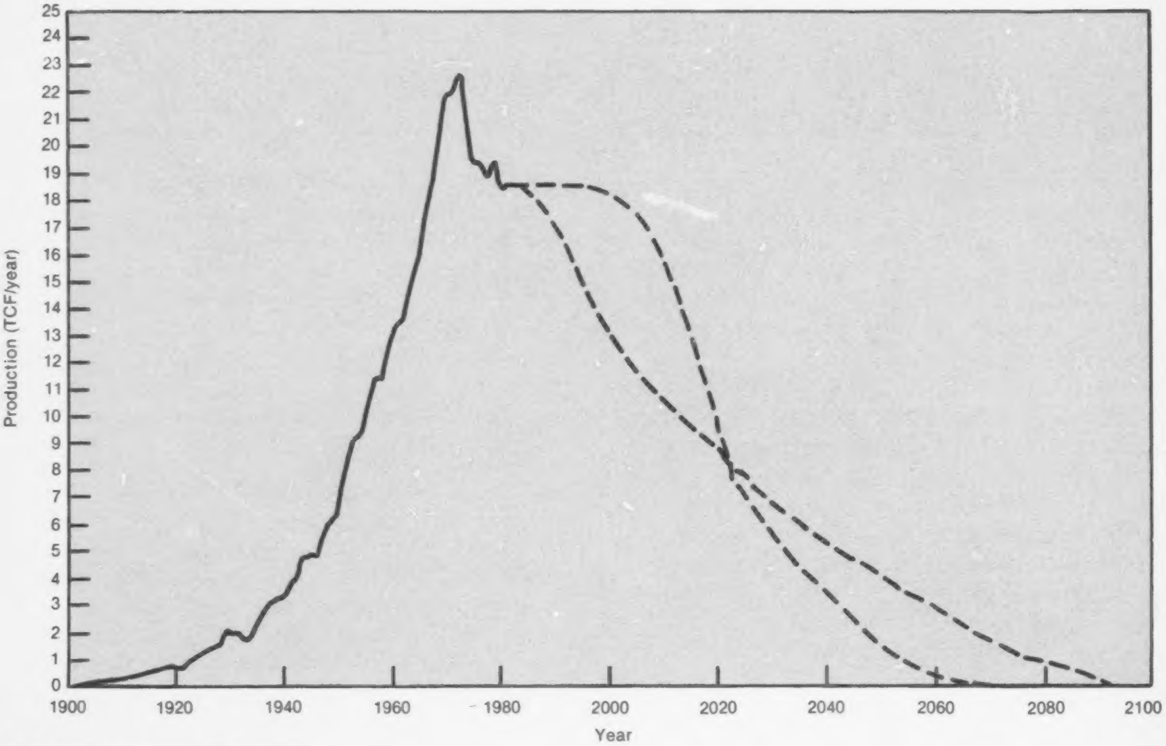
*One such possibility would be a resource base that, while large, had most of its resources in hard-to-find, slow-to-produce fields.

The future production "cycle" would then show a significant production drop in the next 20 to 30 years, followed by a very long period of low but stable production.

Figure 25.—Two Production Futures, One Resource Base: Alternative Representations of Future Production of Conventional Natural Gas in the Lower 48 States, Based on the USGS (1981) Resource Assessment (mean estimate)



SOURCE: Office of Technology Assessment.

the range of resource base estimates cited in table 5 is likely to be a year 2000 range of about 4 to 19 TCF rather than the range of 9 to 19 TCF expressed by the first three projection approaches.*

As discussed in chapter 4, OTA believes that the Hubbert and RAND estimates are overly pessimistic and that a more likely lower bound for the remaining recoverable gas resources is about 400 TCF rather than Hubbert's 244 TCF or RAND's 283 TCF. This higher value is compatible with a 2000 production rate of 9 TCF. Consequently, in our opinion, *a reasonable range for Lower 48 conventional natural gas production for the year 2000 is 9 to 19 TCF*. Similarly, *a reasonable range for 1990 is 13 to 20 TCF.*

Finally, figure 24 illustrates an important point about the current "optimistic" assessments of the recoverable resource base: that these, too, imply an inevitable decline in conventional gas production, although the date of decline is perhaps 20 or 30 years later than that dictated by a pessimistic (400 TCF) resource base assessment. It must be stressed, however, that the additional 20 years or so of leeway implied by the more optimistic assessments may yield sufficient changes in prices and technology to allow either or both the entry of nonconventional gas sources to the market and the movement of large amounts of conventional resources from "subeconomic" to "economic."

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*It is important to remember that the kind of radical drop in production dictated by the most pessimistic of the resource base estimates will likely violate their baseline assumptions of maintenance of existing cost/price relationships—except for Hubbert's assessment (Hubbert believes his methodology "captures" future changes in price/cost relationships and technology). Although many present gas customers can switch without extreme difficulty to oil products or to electricity (assuming supplies of these are available), a rapid drop in production would still tend to push gas prices sharply upwards. This in turn would tend to increase the resource base by moving subeconomic resources into the economic, recoverable category.

These potential sources of gas production are outside the boundaries of the resource base assessments and production forecasts discussed in this technical memorandum, but conceivably they could be extremely important to future U.S. gas production.

PUBLIC AND PRIVATE SECTOR FORECASTS OF FUTURE GAS PRODUCTION

Comparisons of alternative gas production forecasts have many of the same problems as those of comparing gas resource base estimates (see ch. 3, table 4). The economic, regulatory, and other "scenario" conditions assumed for the forecasts are not always made clear. Because the range of reasonable future values/assumptions for these conditions are so broad, it is probably safe to assume that there *are* major scenario differences between different forecasts. The resources measured may differ, with some forecasts including only "conventional" gas and others including all methane sources, especially gas from tight sands. The extent to which some of the commonly used resource base estimates (which are important variables in some of the forecasts, directly determining finding rates or defining an upper limit for cumulative discoveries) contain unconventional resources is not always clear. For example, the PGC acknowledges that as much as 20 percent of its estimated "potential resource" is in tight sands,[18] but other estimates do not specify such a percentage. Consequently, even the forecasters, themselves, do not always know how much tight gas is incorporated in their production forecasts.*

Table 27 presents the results of 21 public and private sector production forecasts of conventional Lower 48 gas production.** Four of the forecasts explicitly include tight sands and/or Devonian shale; these are noted on the table.

A striking feature of the table is that all but one of the forecasts project substantial declines in gas production, most within 10 years and all but the one "dissenter" by 1995. It is important to recognize that these forecasters include some prominent gas "optimists," including AGA. Consequently, much of the current optimism about gas's future apparently stems from projections of supplementary supply from unconventional sources, from Alaska, from Mexico and Canada, and from LNG imports. Chapter 6 provides a brief discussion of the potential from all of these sources except unconventional production.*

The extent of agreement about future gas production displayed in table 27 is in sharp contrast to the very wide range projected by OTA. For the year 2000, a range of 11 to 15 TCF/yr—an extremely narrow range, given different base assumptions, forecasting methods, etc.—would encompass 13 of the 14 estimates available for that date. In contrast, OTA believes that an appropriate range for year 2000 production is 9 to 19 TCF/yr. Part of this difference may be attributed to the fact that most of the values in the table represent forecasts of "most likely" gas production rates, and there may be a tendency for such estimates to cluster together. In conjunction with this possibility, a lack of documentation for many of the forecasts makes it unclear whether they are all independent, original estimates. Some may simply be averages of other forecasts, reflecting the "conventional wisdom."

Of particular interest is a comparison of AGA's year 2000 estimate—12 to 14 TCF/yr—and the production implications of the AGA-supported PGC's gas resource assessment. PGC's assessment seems most compatible with production levels of 15 or 16 TCF/yr, or higher. If the AGA production forecast is intended to be associated with the PGC resource base, then AGA is using a most pessimistic interpretation of the resource base, at least

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[18] Potential Gas Agency, News Release, Feb. 26, 1983.

*Further, there may not be agreement as to what constitutes "tight gas." For example, the Federal Energy Regulatory Commission includes a maximum permeability of 0.1 millidarcies in its definition, while the National Petroleum Council used 1 millidarcy as the limit in its report on unconventional gas sources.

**Including associated/dissolved gas (gas colocated with oil), on a dry basis.

*Unconventional gas potential will be discussed in the final report from this study.

Table 27.—A Comparison of Conventional Lower 48 Natural Gas Supply Forecasts (TCF)

Company	1985	1990	1995	2000
1. Gulf	19.4	18.8	16.7	13.8
2. Texaco	18.9	16.1	14.0	13.0
3. Chevron	18.2	18.0	16.5	14.0
4. Exxon	—	14.6	—	14.1
5. Shell[a]	17.0	13.9	11.5	8.9
6. Conoco[b]	19.0	18.0	—	14.6
7. Union	19.2	18.0	—	—
9. Standard Oil (Indiana)[c]	18.5	17.7	16.5	15.5
10. Tenneco	18.0	15.4	13.5	11.9
11. ANR	15.5	13.6	—	—
12. AGA	16.0-18.0	15.0-17.0	13.5-15.5	12.0-14.0
13. GRI	17.9	15.1	12.8	11.6
14. DOC[c]	—	—	—	12.8
15. GAO	16.5	14.8	14.0	13.5
16. E. Erikson	17.4-18.5	—	—	—
17. EIA	17.3	14.9	14.0	—
18. ICF	16.1	14.3	12.4	—
19. IEA/OECD[b]	16.5-18.0	14.0-17.0	—	11-15
20. Chase Bank[b]	18.3	17.7	—	—
Average	18.1	16.6	15.3	14.3

[a] Marketed gas rather than actual total (dry) production. Excludes increased production from fields that are "forever controlled" under NGPA and that Shell believes could be obtained with decontrol.

[b] Numbers include tight sands.

[c] Averages include interpolated data.

REFERENCES:

1. Gulf Oil Corp., U.S. Energy Analysis Task Group, Pittsburg, Pa., *U.S. Environmental Assessment 1982 Scenarios*, June 1982. "Business as Usual" scenario. (Includes Lower 48 and southern Alaska.)
*2. Texaco Inc., Economics Division, Finance and Economics Department, White Plains, N.Y., *United States Energy Outlook 1980-2000*. February 1981. (Forecast of Marketed Production.)
*3. Standard Oil Co. of California, Economics Department, San Francisco, Calif. Preliminary forecast from forthcoming publication.
4. Exxon Co., U.S.A., Houston, Tex., *Energy Outlook 1980-2000*, December 1980.
*5. Shell Oil Co., Exploration and Production Economics Department, Houston, Tex., *National Energy Outlook to the Year 2000*, July 1982. (Fall 1981 Analysis Dry Marketed Gas.)
*6. Conoco, Inc., Coordinating and Planning Department, Stamford, Conn. *World Energy Outlook Through 2000*, January 1982.
*7. Union Oil Co., Oil and Gas Division, Planning and Valuation, Los Angeles, Calif.
*8. Marathon Oil Co., Economics Department, Findlay, Ohio.
*9. Standard Oil Co. (Indiana), Chicago, Ill. Amoco's forecast includes nonhydrocarbon gases and is specifically done on a dry gas basis. Its 1985 forecast number is demand-constrained.
*10. Tennessee Gas Transmission Co., Economic Analysis and Long Range Planning Department, Houston, Tex., *Energy 1982-2000*, August 1982.
*11. American Natural Resources Co., Detroit, Mich., *United States Energy Outlook 1980-2000*.
12. American Gas Association, Gas Supply Committee, Arlington, Va., *The Gas Energy Supply Outlook: 1980-2000*, January 1982.
*13. Gas Research Institute, Washington, D.C., *Gas Research Insights*, October 1982.
14. U.S. Department of Commerce, Washington, D.C., *U.S. Energy for the Rest of the Century*, July 1982.
15. General Accounting Office, Washington, D.C., *Analysis of Current Trends in U.S. Petroleum and Natural Gas Production*, Dec. 7, 1979.
16. Dr. Edward W. Erickson for Natural Gas Supply Association, *Natural Gas Policy Act: A Pragmatic Analysis*, January 1981.
17. Energy Information Administration, U.S. Department of Energy, Washington, D.C., *1981 Annual Report to Congress*, February 1982.
18. ICF Inc., Washington, D.C., "The Economics of Gas Supply" as published in *The Energy Journal*, vol. 3, No. 4, October 1982.
19. International Energy Agency, OECD, *World Energy Outlook*, Paris, 1982.
20. Chase Manhattan Bank, Energy Economics Division, New York. Best estimate forecast from forthcoming publication.

SOURCE: Jensen Associates, Inc., *Understanding Natural Gas Supply in the United States* Contractor Report to the Office of Technology Assessment, April, 1983.

from the standpoint of maintaining production rates at high levels during the next few decades.

OTA undertook to evaluate and compare both the general methodologies associated with these forecasts and, in a few cases, the specific assumptions and methodological decisions made by individual forecasters. However, many of the forecasts are based, in large part, on proprietary information, and needed details were unavailable. Also, several of the forecasts made by the large energy companies depend heavily on judgmental procedures rather than on formal computerized models, and these forecasts would have been difficult to document and evaluate even if the companies had desired public scrutiny of this sort. In addition, several of the models ostensibly available for public scrutiny do not, in fact, have adequate documentation. A background document to this report will present OTA's staff review of modeling methodologies and of some specific models. The document will also present a review of modeling methodology by James Jensen, president of Jensen Associates, an OTA contractor.

Chapter 6

Other Gas Sources—Summary

Chapter 6

Other Gas Sources—Summary*

Natural gas imports in 1981 totaled 904 billion cubic feet (BCF)[1] and composed 4.6 percent of the total U.S. dry gas consumption. As recently as 1979, however, imports constituted as much as 6.1 percent of the total U.S. dry gas consumption. The current import status and future import projections are summarized in table 28.

In evaluating "other" potential supplies of natural gas, the most obvious sources are the border countries, Canada and Mexico. Canada has been and probably will remain our most important source of supplemental natural gas. In January 1983, the National Energy Board recommended an additional 9.25 trillion cubic feet (TCF) of reserves for export. Although this decision nearly doubles the exportable quantity available to the United States, actual imports are expected to remain low in the near-term, owing to decreased U.S. demand and noncompetitive pricing. In the long run, the increase in allowable exports will probably help encourage frontier development.

Exports from Mexico will probably remain at 300 million cubic feet (MMCF/day) in the near-term, consistent with what they have been since the present contract was negotiated in 1979. Although Mexican natural gas supplies are bountiful, the Mexican Government's current export philosophy seems to preclude significant increases in exports to the United States. Mexican consumption is expected to increase as the distribution infrastructure develops.

Alaska represents another large potential supply; the Prudhoe Bay Field alone constitutes over 10 percent of the total U.S. proved reserves. At present, there is no natural gas production reaching the Lower 48 States, owing to the lack of a means of transportation. Financing for a transportation project is difficult to obtain because of cur-

Table 28.—Natural Gas Imports Summary Table

Source	Natural gas supplied to Lower 48 States in 1981	Allowable imports under 1982 licenses/contracts	Proved reserve estimates	Range of future export estimates[a]	
				1990	2000
Mexico	0.1 TCF (EIA)	0.1 TCF	75 TCT (PEMEX)	0.1-1.0 TCF	0-2.0 TCF
				(AGA, LA-Mexico)	
Canada	0.8 (EIA)	1.8 TCF	88 TCF (CPA)	1.0-2.5 TCF	1.0-3.0 TCF
				(AGA, LA-Canada)	
Alaska	0	—	32 TCF (USGS, PGC)	ANGTS[b]	
				0.7-1.2 TCF	1.2-2.4 TCF
				Pacific-Alaskan LNG	
				0.1 TCF	0.2-0.4 TCF
				(AGA)	
LNG	0.04 (AGA/GER)	0.9 TCF[c]	N.A.	Variable—depends on future U.S. policy and pricing.	
Total	0.9 TCT (EIA)				

[a] This range represents the highest and lowest estimates of the references cited.
[b] Alaskan Natural Gas Transportation System.
[c] This value represents the total contract volumes for completed terminals.

REFERENCES:

AGA—American Gas Association, *The Gas Energy Supply Outlook: 1980-2000*, January 1982.
AGA/GER—American Gas Association, *Gas Energy Review*, June 1982.
CPA—Canadian Petroleum Association, *Statistical Handbook*, 1980.
EIA—Energy Information Administration, *U.S. Imports and Exports of Natural Gas, 1981*, June 1982.
LA—Canada—Lewin & Associates—*Canadian Natural Gas: A Future North American Energy Source?* January 1980.
LA—Mexico—Lewin & Associates—*Future Mexican Oil and Gas Production*, July 1979.
PEMEX—In American Gas Association, *Gas Energy Review*, December 1982.
PGC—Potential Gas Committee, *Potential Supply of Natural Gas in the U.S.*, May 1981.
USGS—United States Geological Survey, Circular 860.

SOURCE: Office of Technology Assessment.

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*This chapter summarizes a detailed discussion to be published in the background report to this technical memorandum.

[1] U.S. Department of Energy, Energy Information Administration, "U.S. Imports and Exports of Natural Gas, 1981," June 1982.

rent surplus supply and market prices below levels necessary for financial success. Despite a waiver package to eliminate roadblocks to private financing, the Alaska Natural Gas Transportation System project still has not achieved adequate financing arrangements. The rival, recently proposed TransAlaska Gas System would enable North Slope gas to be marketed outside of the domestic market. A methanol conversion alternative would allow the gas to be marketed either domestically or internationally. Neither of these alternatives appear to have good prospects for the immediate future.

Throughout the early to mid-1970's, liquefied natural gas (LNG) contracts were viewed as a favorable means of achieving long-term natural gas supplies. Since that time, the supply scenario has changed significantly, and LNG purchasers are now confronted with high-priced gas during a time of gas surplus. In the near term, there is little incentive to increase LNG imports; however, the availability of the long-term contracts and the opportunity to diversify U.S. supply may prove to be attractive in the future.

MEXICO

Mexico had reported 75.4 TCF of proved reserves as of December 1981. Within the last 4 years, large reserve additions have caused Mexico's reserve-to-production ratio to double from 30 to 60.

Most of Mexico's gas production is from wells associated with oil; nonassociated wells are typically not put into production. This practice reflects Mexico's policy of exporting oil and using natural gas primarily to meet domestic energy demands. Mexico exports only the surplus gas remaining after domestic demand is met, which is the primary limiting factor to export levels. Mexico's current export level of 110 BCF/yr was established in 1979 by a contract with Border Gas, a U.S. pipeline company.[2] This quantity is recognized as a compromise between Mexican policymakers, who believe energy exports are necessary to bolster Mexico's ailing economy, and those who believe the resource should be saved for future domestic use.

Mexico has been successful in encouraging conversions to natural gas, and, as a result, domestic gas demand has been growing at a rate of 13 percent per year.[3] Because Mexico's financial condition has precluded investment in distribution equipment, the primary constraint to increased domestic consumption is a lack of transmission and distribution capability. As the distribution system develops and the process of converting end users to gas progresses, domestic consumption will increase, which could further constrain the exportable surplus.

Substantial increases in the export level are not expected in the near term. Early in 1982, the Mexicans talked of increasing exports to 500 MMCF/day and later to 1,000 MMCF/day; however, these plans were not carried out, owing to problems with gas-gathering systems and budget cutbacks.[4]

There is a considerable range of estimates for the future quantity of Mexican gas available for export to the United States. In their "high success" case, Lewin and Associates estimate that annual exports will rise to 766 BCF in 1990 and then decrease to 255 BCF by 1995 and 0 by 2000.[5] The American Gas Association (AGA) is considerably more optimistic in its long-run projections and estimates that between 100 and 1,000 BCF/yr will be available in the 1990's and between 100 and 2,000 BCF/yr will be available by 2000.[6]

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[2] Border Gas is owned and controlled by six interstate pipeline companies: Tennessee Gas Transmission Co., Texas Eastern Transmission Corp., El Paso Natural Gas Co., Transcontinential Gas Pipeline Corp., Southern Natural Gas Co., and Florida Gas Transmission Co.

[3] *Petroleum Intelligence Weekly*, Special Supplement, "Mexico's Expanding Role in World Oil Markets," June 28, 1982.

[4] Ibid.

[5] Lewin and Associates, *Future Mexican Oil and Gas Production*, July 1979.

[6] American Gas Association, *The Gas Energy Supply Outlook: 1980-2000*, January 1982.

CANADA

Canada also has large natural gas reserves, estimated at 88.4 TCF by the Canadian Petroleum Association. Its ultimately recoverable resource base estimate of 420 TCF[7] could be increased considerably by developing unconventional gas in Western Canada. At present, the technology to produce most of these low permeability reservoirs has not been demonstrated.

Marketability problems have created a large surplus export capability. In January 1983, in an attempt to alleviate the situation, the National Energy Board nearly doubled the exportable quantity of gas available to the United States. Also, in April 1983, the price was reduced from $4.94 per thousand cubic feet (MCF) to $4.40 per MCF to compete more readily in the U.S. market. However, despite these efforts, the price differential, decreased U.S. demand, and improved short-term domestic supply prospects are still expected to keep U.S. imports of Canadian gas low in the near term.

The 1980 National Energy Plan (NEP) is expected to have far-reaching effects on the Canadian petroleum industry. The NEP established guidelines aimed at enabling Canada to achieve energy self-sufficiency by 1990. Several NEP objectives include:

- encourage substitution of gas for oil by favorable pricing;
- increase Canadian ownership of the domestic petroleum industry to 50 percent by 1990;
- stimulate frontier exploration off the East Coast and in the Arctic;
- allow a 25 percent back-in interest for the Canadian Government on federal leases; and
- increase the Canadian Government's share of petroleum revenues relative to those received by industry and the producing provinces.

The increased regulation of the NEP has had a noticeable negative impact on risk investment. Canadian operators and support companies have left Canada for more lucrative prospects in the United States. Many petroleum companies have cut expenditures and long-term projects and suffered severe losses. These effects could lessen the quantity of gas produced in the remainder of the century, thereby limiting the availability of surplus for export to the United States.

Another factor affecting gas export is the level of Canadian gas consumption. In an attempt to reduce the need for expensive foreign oil imports, the Canadian Government is encouraging increased use of natural gas and has provided several incentives for doing so, such as favorable gas prices, grants, and loans. The NEB forecasts natural gas demand to increase at 4 percent per year during the 1980's and 3 percent per year throughout the 1990's.[8] Although the conversion process is progressing slowly, the quantity of gas available to the United States could be constrained if Canadian consumption increases substantially in the future.

Under current Canadian export agreements, natural gas exports will increase to about 1.6 TCF/yr by 1990 and then decline to about 0.15 TCF/yr by 2000.[9] AGA estimates that between 1.0 and 1.7 TCF/yr will be exported by 1990 and 1.0 to 2.0 TCF/yr by 2000.[10] Lewin and Associates believe that technological advances in the frontier areas and the development of unconventional gas could allow exports of 2.5 and 3.0 TCF/yr in 1990 and 2000, respectively.[11]

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[7] R. M. Procter, P. J. Lee, and D. N. Skibo, "Canada's Conventional Oil and Gas Resources" Geological Survey of Canada, Open File 767, March 1981, p. 27.

[8] National Energy Board, "Omnibus '82 Backgrounder," Jan. 27, 1983.

[9] Ibid.

[10] American Gas Association, *The Gas Energy Supply Outlook: 1980-2000*, January 1982.

[11] Lewin and Associates, *Canadian Natural Gas: A Future North American Energy Source*, January 1980.

ALASKA

The massive hydrocarbon potential of Alaska was realized with the discovery of the Prudhoe Bay Field in 1968, which added 26 TCF to estimated U.S. proved gas reserves. Reserve estimates for Alaska average 32 TCF, and resource base estimates are as high as 145 TCF.[12]

Despite the substantial quantity of reserves in Alaska, lack of a transportation system has precluded marketing of Alaskan gas to the Lower 48 States. The Alaskan Natural Gas Transportation Act of 1976 directs the President, subject to congressional approval, to establish a means to transport Alaskan natural gas to the Lower 48 States. To ensure domestic use of the resources, the Export Administration Act of 1979 forbids the export of North Slope hydrocarbons to non-U.S. customers. Several transportation methods have been proposed; not all of these have designated the Lower 48 States as the final market.

In September 1977, the Alaskan Natural Gas Transportation System (ANGTS) was chosen over several alternatives. The 4,800-mile pipeline was to be routed from Prudhoe Bay across Alaska and Canada to Alberta, and split into a western leg to California and an eastern leg to Illinois. Despite a waiver submitted by President Reagan and approved by Congress in mid-December 1981, to remove any legislative deterrents to private financing, the pipeline has not yet been financed. Investment capital has been difficult to attract because the marketability of the gas is questionable. ANGTS is estimated to cost between $38.7 billion and $47.6 billion[13] and deliver gas at prices estimated between $4.85 per MCF[14] and $20 per MCF.[15] ANGTS is the only transportation scheme designed to market North Slope natural gas in the Lower 48 States. AGA estimates that between 0.7 TCF and 1.2 TCF could be available by 1990 and 1.2 TCF to 2.4 TCF by 2000, depending on when the pipeline is completed.[16]

Converting North Slope gas to methanol could provide an alternative market for the gas. The principal advantage of the methanol option is that the existing oil pipeline system could be used to transport the methanol from the North Slope to Valdez, assuming capacity were available. The major problems with the methanol alternative are the high energy loss associated with conversion and the potential that future demand for methanol might be insufficient to absorb Alaskan production. Also, costs would be very high; estimated first year costs for conversion and transportation range between $14.24 and $17.24 per million Btu.[17]

Two LNG projects have been proposed to market Alaskan gas. The Alaska Governor's Economic Committee recommended the TransAlaska Gas System (TAGS). The TAGS requires an 820-mile pipeline from the North Slope to the Kenai Peninsula, where the gas would be liquefied and shipped to foreign markets, principally Japan. If this proposal is adopted and an executive order or legislation declaring gas exports to be in the national interest is obtained, the Lower 48 States may never receive supplemental gas from the North Slope. Another LNG proposal, the Pacific Alaska LNG Project, calls for the shipment of south Alaskan LNG to receiving facilities on the California coast; however, the potential supply contribution from this project is small. AGA estimates 0.1 TCF could be supplied by 1990 and between 0.2 and 0.4 TCF by 2000, depending on the construction schedule.[18]

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[12] Potential Gas Committee, *Potential Supply of Natural Gas in the U.S.*, May 1981.

[13] American Gas Association, *Gas Energy Review*, vol. 10, No. 1, January 1982.

[14] *International Gas Technology Highlights*, "Alaskan Pipeline Costs Could Be Lower Because of Delay: Northwest Heat," Aug. 30, 1982.

[15] *Oil and Gas Journal*, "Angts Seen Top Option for Alaskan Gas," Aug. 9, 1982, p. 61.

[16] American Gas Association, *The Gas Energy Supply Outlook: 1980-2000*, January 1982.

[17] Congressional Research Service, *Major Issues Associated With the Alaska Natural Gas Transportation Waivers*, Dec. 18, 1981.

[18] American Gas Association, *The Gas Energy Supply Outlook: 1980-2000*, January 1982.

LIQUEFIED NATURAL GAS

During the early to mid-1970's, when the United States was confronted with natural gas shortages, LNG imports appeared to be a favorable supplemental supply alternative. Several long-term contracts were established with Algeria. Since then, the supply situation has changed drastically, and in the midst of a natural gas surplus, LNG purchasers are confronted with very high-cost gas supplies.

Although existing agreements enable imports of up to 800 BCF per year, the U.S. imported only 61 BCF of LNG in 1982 at two of four existing receiving facilities. The Distrigas facility in Everett, Massachusetts, received 34.0 BCF and the Lake Charles, Louisiana, facility received 27.0 BCF since its first shipment in September 1982. Small amounts of LNG were also trucked from Canada to New England. Also in 1982, the United States exported 55.9 BCF from Cook Inlet, Alaska, to Japan, and in 1981 was a net exporter of LNG.[19]

For purposes of evaluating future LNG availability, the LNG resource base includes any large reserves which, owing to remote location or lack of a transportation method, are not committed to existing markets. In 1978 OTA estimated that of the 2,257 TCF of proved reserves in the world, about 812 TCF were surplus (635 TCF of the surplus are located in the U.S.S.R., Iran, and Algeria[20]). Although reserves are plentiful, high costs preclude a large percentage of natural gas reserves from being made available as LNG. The total capital required for a world-scale LNG facility (1 BCF/day) is around $5 billion (in 1978 dollars). Generally, 40 percent is required for production and liquefaction, 40 percent for transportation, and 20 percent for receiving and vaporization facilities.[21]

The future of LNG depends principally on pricing and policy. If the producing country is willing to accept a price that achieves parity with the price of oil at the burner tip, the future of LNG is considerably brighter than if the oil parity price is demanded at the wellhead. The additional costs for liquefaction and transportation are reflected in the burner-tip price, which, if too high, is not competitive with oil and is not economically justifiable. Currently, the price of LNG is higher than market-clearing levels, and lower cost gas is used as a cushion to moderate the price. This average pricing concept is often criticized for substituting high-cost imports for lower priced alternatives, creating a potential misallocation of resources. Also, from a policy standpoint, importing foreign supplies of natural gas, particularly from a member of OPEC, is not consistent with U.S. goals of reducing energy dependence.

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[19] U.S. Department of Energy, Energy Information Administration, "U.S. Imports and Exports of Natural Gas, 1981," June 1982.

[20] Office of Technology Assessment, *Alternative Energy Futures, Part. 1, The Future of LNG,* March 1980.

[21] Ibid.

Appendix

Appendix A

Glossary

anaerobic: Conditions that exist only in the absence of oxygen.

anticline: A fold, generally convex upward, whose core contains stratigraphically older rocks.

associated dissolved gas: Natural gas that occurs together with oil in a reservoir, either dissolved in the oil (dissolved gas) or as a gas cap above the oil (associated gas).

combination trap: A trap for oil or gas that has both structural and stratigraphic elements.

extension test: A well drilled to extend the areal limits of a partially developed pool. May sometimes become a new pool discovery well. Also known as *outpost test*.

field: Composed of a single pool, or multiple pools that are grouped on or related to a single structural and/or stratigraphic feature.

formation: A rock mass composed of individual beds or units with similar physical characteristics or origin.

formation water: Water present in a water-bearing formation under natural conditions, as opposed to introduced fluids, such as drilling mud.

new field wildcat: A well drilled in search of oil or gas in a geological structural feature or environment that has never before been proven productive.

new pool wildcat: Well drilled in search of pools above (shallower pool test), below (deeper pool test), or outside the areal limits of already known pools in fields that have already been proven productive. May sometimes become an extension well.

nonassociated gas: Natural gas that occurs in a reservoir without oil.

outpost test: See *extension test*.

permeable: Having the property or capacity of a porous rock, sediment, or soil for transmitting a fluid; it is a measure of the relative ease of fluid flow under unequal pressure.

petroleum: A general term for all naturally occurring hydrocarbons, whether gaseous, liquid, or solid.

play: A rock formation or group of formations within a sedimentary basin with geologic characteristics similar to those that have been proven productive. A play serves as a planning unit around which an exploration program can be constructed. May also refer to the exploratory effort, often following a significant discovery, that uses a geologic idea to determine where petroleum can be found.

pool: A subsurface accumulation of oil and/or gas in porous and permeable rock, having its own isolated pressure system. Theoretically, a single well could drain a pool. Also known as a *reservoir*.

porosity: The percentage of the bulk volume of a rock or soil that is occupied by interstices (gaps between the particles that compose the rock), whether isolated or connected.

prospect: An area that is a potential site of economically recoverable petroleum accumulation based on preliminary exploration.

province: A region in which a number of oil and gas pools and fields occur in a similar or related geological environment.

reserves: Usually refers to oil or gas that has been identified by drilling or extrapolation from drilling and is recoverable at current prices and technology. Proved reserves are identified and estimated directly by engineering measurements; in most cases, only the drilled portion of fields is included in this category.

reservoir: See *pool*.

reservoir rock: Any porous and permeable rock that yields oil or gas. Sandstone, limestone, and dolomite are the most common reservoir rocks, but gas accumulation in the fractures of less permeable rocks also occurs.

resources: The total amount of oil or gas that remains to be produced in the future. Generally does not include oil or gas in such small deposits or under such difficult conditions that it is not expected to be produced at any foreseeable price/technology combination.

secondary migration: The movement of fluids within the permeable reservoir rocks that eventually leads to the segregation of oil and gas into accumulations in certain parts of these rocks.

sedimentary basin: A low area in the Earth's crust, caused by earth movements, in which sediments have accumulated.

sedimentation: The act or process of forming or accumulating sediment in layers, including such processes as the separation of rock particles from the material from which the sediment is derived, the transportation of these particles to the site of deposition, the actual deposition or settling of the particles, the chemical or other changes occurring in the sediment, and the ultimate consolidation of the sediment into solid rock.

source rock: Sedimentary rock in which organic material under pressure, heat, and time was transformed to liquid or gaseous hydrocarbons. Source rock is usually shale or limestone.

stratigraphic trap: A trap for oil or gas, resulting from changes in rock type, porosity, or permeability, that occurs as a result of the sedimentation process rather than structural deformation.

structural trap: A trap for oil or gas resulting from folding, faulting, or other deformation of the Earth.

trap: Any barrier to the upward movement of oil or gas that allows either or both to accumulate. A trap includes a reservoir rock and an overlying impermeable roof rock; the contact between these is concave, as viewed from below. See also *stratigraphic, structural,* and *combination traps.*

U.S. GOVERNMENT PRINTING OFFICE : 1983 O - 24-358

Office of Technology Assessment

The Office of Technology Assessment (OTA) was created in 1972 as an analytical arm of Congress. OTA's basic function is to help legislative policymakers anticipate and plan for the consequences of technological changes and to examine the many ways, expected and unexpected, in which technology affects people's lives. The assessment of technology calls for exploration of the physical, biological, economic, social, and political impacts that can result from applications of scientific knowledge. OTA provides Congress with independent and timely information about the potential effects—both beneficial and harmful—of technological applications.

Requests for studies are made by chairmen of standing committees of the House of Representatives or Senate; by the Technology Assessment Board, the governing body of OTA; or by the Director of OTA in consultation with the Board.

The Technology Assessment Board is composed of six members of the House, six members of the Senate, and the OTA Director, who is a nonvoting member.

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